July 15, 2021

The Honorable Chair and Members
of the Hawai‘i Public Utilities Commission
Kekuanao‘a Building, First Floor
465 South King Street
Honolulu, Hawai‘i 96813

Dear Commissioners:

Subject: Docket No. 2017-0352 – To Institute a Proceeding Relating to a Competitve Bidding Process to Acquire Dispatchable and Renewable Generation
Draft "Hawai‘i Island Near Term Grid Needs Assessment"

The Hawaiian Electric Companies[1] respectfully submit the attached July 2021 *Hawai‘i Island Near-Term Grid Needs Assessment* report. This draft report describes the methodology and inputs used to study scenarios whose results were then used to inform recommendations for Grid Needs for solution sourcing for the Stage 3 Request for Proposals ("RFP") for Hawai‘i Island. In the Commission's letter dated April 20, 2021, the Commission supported the Hawaiian Electric Companies' efforts to conduct studies to guide the development of the Stage 3 RFP for Hawai‘i Island, and this report provides the latest update on its progress.

The Companies respectfully provide a copy of this report for the Commission's review herewith and are preparing to present the draft results of the *Hawaiì Island Near-Term Grid Needs Assessment* to the Integrated Grid Planning ("IGP") stakeholder technical working group through a virtual meeting scheduled for 9:30 to 11:30 am HST on August 4, 2021. The Companies will host this meeting virtually and participants will be able to provide input and comment directly to the Companies for consideration while developing the draft Stage 3 RFP. To ensure maximum participation, the Companies will provide meeting information via email to past procurement participants, interested developers, aggregators, and renewable energy advocates as well as post information on the meeting on our website. A recording of the meeting will be made available for viewing no later than August 11, and the Companies will encourage stakeholders to submit feedback until August 25.

The Companies appreciate the Commission's guidance and looks forward to futher discussion about the report's results and the scope development of the Stage 3 RFP for Hawai‘i Island at the IGP stakeholder meeting.

[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawai‘i Electric Light Company, Inc., and Maui Electric Company, Limited.

Sincerely,

/s/ Marc Asano

Marc Asano
Director, Integrated Grid Planning

Enclosure

c: Division of Consumer Advocacy

Hawai‘i Island

Near-Term Grid Needs Assessment

Draft Report

July 2021

Prepared By:
Hawaiian Electric
System Planning

Version History

Version	Date	Description
1	July 2021	Draft Release for Comment
2		
3		

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Executive Summary

Hawaiian Electric is committed to advancing decarbonization of the electric sector on Hawaiʻi Island. Following recent low-cost renewable projects procured for Hawaiʻi Island, Hawaiian Electric performed a Grid Needs Assessment to identify Grid Needs[1] to cost-effectively increase levels of renewable energy. In 2020, the Hawaiʻi Island system achieved a renewable portfolio standard of 43%. By 2025 Hawaiʻi Island may reach upwards of 120% renewable energy of electric sales.

This Grid Needs Assessment report (“Report”) follows the Integrated Grid Planning (“IGP”) process, assessing Hawaiʻi Island’s Grid Needs based on a capacity expansion optimization analysis to add new cost-effective resources and identification of Grid Needs, a reliability assessment of the system, validation of the operations of the future system through production cost simulations, and a transmission and system security assessment.

Through various near-term scenarios and sensitivities, the Grid Needs Assessment identified Grid Needs under different potential outcomes over the next 10 years. A number of potential changes to the Hawaiʻi Island energy mix are possible over the near-term – the following scenarios evaluated these potential outcomes:

- Status Quo – Uses IGP planning assumptions with Stage 1 and 2 renewable projects, CBRE Phase 1 and 2, and GSPA contracts in-service. All other existing power purchase agreements (“PPAs”) are assumed to terminate at the end of their current contract terms, except for PGV which is assumed to continue through the planning horizon.

- Scenario 1: Base Scenario – The reference case uses the IGP planning assumptions where new resources are allowed to be built. The Base Scenario assumes the Puna Geothermal Venture facility (“PGV”) remains under its existing contract at 38 MW. PPAs for the Hamakua Energy Partners (“HEP”) facility and existing variable renewable projects are assumed to terminate at the end of their contract term to allow for their capacity to be re-optimized. The Base Scenario also assumes a managed charging profile for electric vehicles.

- Scenario 2: PPA Contract Extensions Scenario – Using the Base as a reference, this scenario assumes that the 8 MW PGV expansion is in service in 2024 under the proposed amended contract. PPAs for existing variable renewable projects are assumed to continue through the planning horizon. These projects include Hawi Wind, Wailuku River Hydro, and Pakini Nui Wind.

[1] “Grid Needs” means the specific grid services (including but not limited to capacity, energy and ancillary services) identified in the Grid Needs Assessment, including transmission and distribution system needs that may be addressed through a non-wires alternative.

- Scenario 3: PGV and Hu Honua Scenario – Using the Base as a reference, this scenario assumes that the 8 MW PGV expansion is in service in 2024 under the proposed amended contract and Hu Honua is in service in 2022. Other PPAs terminate at the end of their contract terms as assumed in the Base.

- Scenario 4: High Electrification Scenario – Using the Base as a reference, the electric vehicle layer of the sales forecast was increased by 30%.

As shown in Figure ES-1-1 under all scenarios, Hawai'i Island can make significant progress in their RPS if the identified Grid Needs are fulfilled.

Figure ES-1-1: RPS Under Various Scenarios in the Near-Term

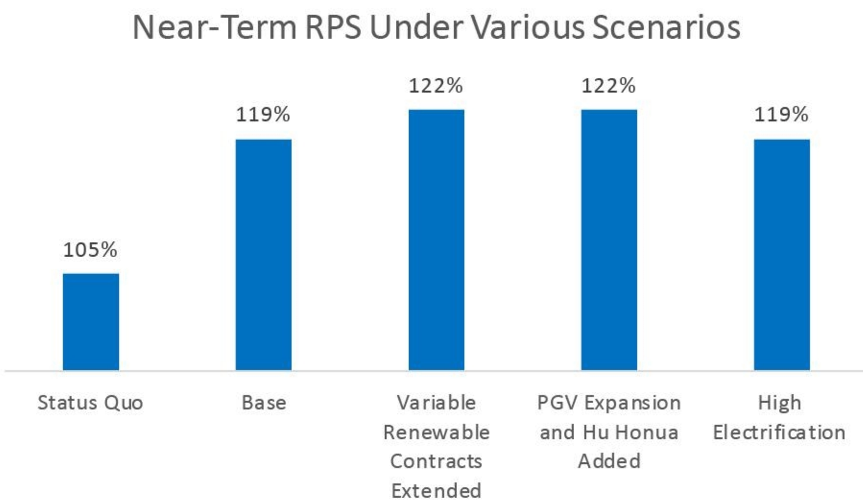

Figure ES-1-2, below, identifies the quantity of each Grid Need in the modeled Year 2025 to advance RPS as described above in a cost-effective and reliable manner. The identified Grid Needs are not required to be in-service by 2025 for reliability reasons. Sourcing the Grid Needs through the solution sourcing process should provide sufficient flexibility in the commercial operations date to allow for other technologies that may take longer to develop but provide diversification, resilience, or other benefits. Across various scenarios, the Grid Needs are similar, which allows a "least regrets" pathway to be pursued.

Figure ES-1-2: Grid Needs Portfolio Under Various Scenarios

Grid Need	Year	Scenario 1: Base	Scenario 2: PPA Contract Extensions	Scenario 3: PGV and Hu Honua	Scenario 4: High Electrification
Energy, GWh[2]	2025	265.3	206.2	299.9	269.8
Load Reduce, MW	2025	56.2	57.7	65.5	69.3
Load Reduce, Calls/Year	2025	67	55	39	16
Load Reduce, Hours/Call	2025	2.9	2.1	2.8	1.8
Load Build, MW	2025	13.5	16.6	9.9	14.5
Load Build, Calls/Year	2025	198	148	218	208
Load Build, Hours/Call	2025	1.1	1.1	1.1	1.1
Up Reg, MW	2025	61.2	47.3	43.8	61.3
Up Ramp, MW	2025	28.5	28.9	28.6	28.5
Down Reg, MW	2025	22.4	22.2	22.8	24.9
Down Ramp, MW	2025	16.0	16.6	16.1	17.7
ERM, MW	2025	0.0	0.0	0.0	0.0

A transmission needs assessment was performed using recent studies to inform a system security assessment. High level system security recommendations include requiring grid-forming control on new resources, the need for inertia to limit the rate of change of frequency during system events, voltage support requirements, and fault current to maintain the efficacy of the distribution protection system.

Additionally, a steady state analysis was performed to assess the transmission system capacity and voltage constraints. From the high-level analysis, the near-term steady-state needs for the proposed scenarios are identified as follows:

1. Voltage support needs in East Hawaiʻi require operation of a minimum number of the existing generating units (i.e., Hill 5 and/or 6 and/or Puna Steam);
2. Voltage support needs in South Hawaiʻi depend on the wind farm located in the southern part of the island; and
3. Potential future thermal overloads in the Waikoloa area will occur if additional future generation is connected near the area.

If the existing wind farm in the southern part of the island does not continue past its current PPA term, replacement of generation at or near the same areas are needed. Voltage requirements in East Hawaiʻi can be met without operation of synchronous generating units in the area through addition of dynamic reactive power sources (e.g., synchronous condenser conversions or additions, static var compensator) on the east side of the island or by reconductoring the L6200 transmission line.

[2] Load build and load reduce are a subset of the energy grid need and represent opportunities to shift energy throughout the year.

Future detailed studies will also need to be performed to evaluate other resource needs such as dynamic voltage support and fast frequency response ("FFR"), which are expected to be covered in upcoming system stability studies.

The Report also considers enhancements to system resilience. The Grid Needs portfolios were tested against low renewable conditions to determine whether poor wind and solar conditions would impact the reliability of the system. The analysis did not find any significant impacts to reliability due to prolonged poor weather conditions. Geographic diversity of resources was also considered in the transmission needs analysis. Hawaiʻi Island is unique in its transmission system, which requires balanced generation supplied from different areas of the island to avoid voltage collapse and transmission congestion locally or on cross-island transmission lines, but alternatively, offers potential for geographic and resource diversity. High-level analysis and past analyses conclude that generation heavily provided by one area of the island can result in low voltage violations on the opposite side of the island or cross-island transmission tie-line overloads. The recent Stage 1 and 2 procurements selected 120 MW of solar and energy storage systems in West Hawaiʻi. Therefore, new resources should be located in East Hawaiʻi for reliability and resilience.

The Company evaluated existing transmission substations available for interconnection with the intention of streamlining and lowering interconnection costs. The preliminary results of the transmission capacity analysis indicate there is ample capacity at existing substations located in East Hawaiʻi for future Stage 3 resources.

1. Introduction

On January 21, 2021, the Public Utilities Commission requested Hawaiian Electric develop a Stage 3 RFP for Hawaiʻi Island. On February 25, 2021, Hawaiian Electric filed its response to the Commission's letter in support of the development of a Stage 3 RFP based upon an updated assessment of Grid Needs. In developing that assessment, the Company proposed developing a Base Scenario as well as sensitivity analyses to examine the impact of thermal resources in the earlier part of the planning horizon and to analyze how the Base Scenario performs under periods of low variable renewable generation. On April 20, 2021, the Commission provided additional guidance, requesting that Hawaiian Electric endeavor to complete the studies by July 15, 2021 and file the draft Stage 3 RFP in the docket no later than October 15, 2021.

The Grid Needs Assessment contained herein describes the methodology and inputs used to define and evaluate several planning scenarios as well as how the results of the scenario analyses were used to inform the recommendations for Grid Needs for solution sourcing.

Included in this Report is a high-level system security assessment intended to present past study results and high-level analysis results in order to inform the resource procurements for Stage 3 RFP, to identify the current understanding of the state of system security on Hawaiʻi Island, to identify areas and conditions of high risk operation, and to identify remaining gaps for resource needs with the need for continued detailed studies.

It is important to note that the resource needs identified in this Report are based on the current studies performed to date and do not preclude other resources needs that have not been identified or studied at this time. Not all risks are encapsulated in this Report nor identified at this time. A more detailed system security assessment is in progress, which will further inform resource requirements.

2. Methodology

The Company used the analytical framework developed in the IGP process to identify the Grid Needs for near-term solutions sourcing. As shown in Figure 2-1, multiple tools were used to determine the Grid Needs.

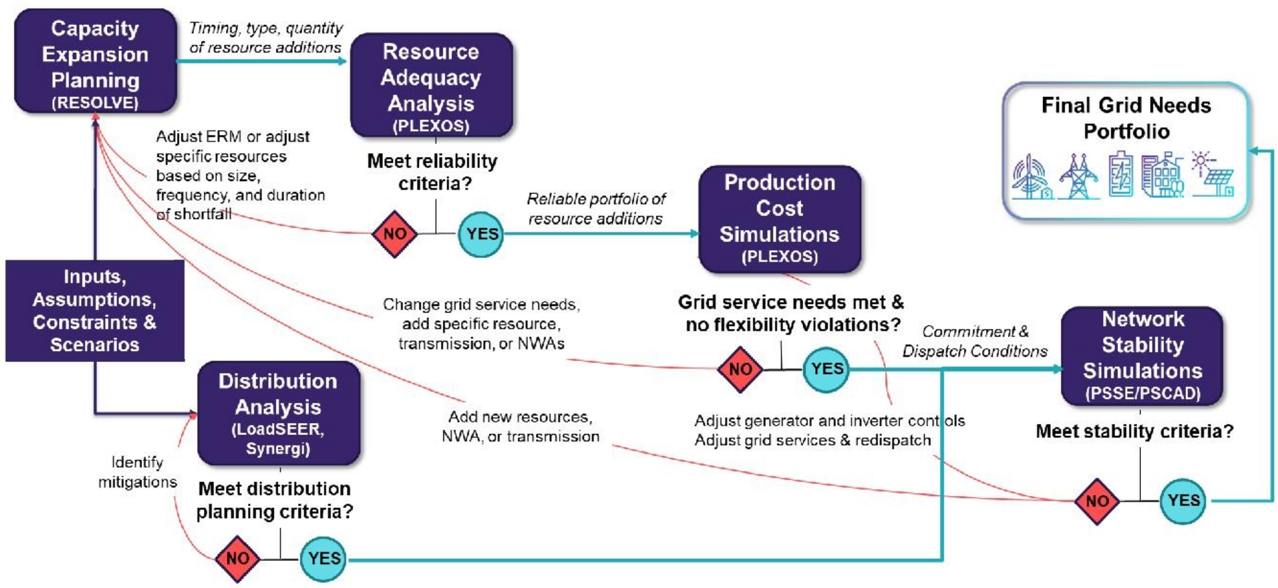

Figure 2-1: Grid Needs Assessment Methodology

As described in this Report, RESOLVE determined the optimal type, quantity, and timing of resource additions across a range of constraints to provide directional Grid Needs under various scenarios. An energy reserve margin ("ERM") analysis was performed in PLEXOS to check the reliability of the various scenarios under study, and finally a production cost simulation was performed to verify the operations of the Grid Needs using proxy resources providing the identified grid services. The Base Scenario was then used in the transmission needs step where a high-level network stability assessment (also known as system security) was performed as well as power flow analysis to determine thermal and voltage needs on the system. The Grid Needs Assessment did not require any modeling iterations. A distribution analysis was not performed in this Grid Needs Assessment; however, such analysis will be performed as part of the IGP process. Currently, there are no major capital investments planned for Hawaiʻi Island based on load growth.

2.1. RESOLVE Capacity Expansion and PLEXOS Production Simulation Analysis

The Grid Needs Assessment uses the planning assumptions developed in the IGP process to determine a baseline, or "Base" portfolio of Grid Needs. The portfolio was developed using the RESOLVE and PLEXOS models to identify and verify the Grid Needs through 2034. RESOLVE produced an optimized resource plan of proxy resources that could fulfill the Grid Needs. The primary objective of this phase of the process was to identify Grid Needs using proxy resources for the assumed input conditions (i.e., resources are assumed to be retained, removed and added). The optimized resource plan produced by RESOLVE was then evaluated in PLEXOS, an hourly production simulation, to verify the operations and dispatch of the resources on the system. The resources selected by RESOLVE between 2025-2029 were assumed to be installed in 2025, and the resources selected by RESOLVE between 2030-2034 was assumed to be installed in 2030. Grouping resources in this manner helps to define the grid services that could be acquired in tranches for future procurements.

2.2. Reliability Analysis

The Company performed a separate ERM analysis on each of the scenarios to determine any capacity reliability needs. To determine the capacity need, the Status Quo scenario was used that did not include any of the new proxy resources selected by RESOLVE. The need for additional capacity was determined by the unserved energy observed in the hours where the net load, increased by the 30% ERM guideline, was not met by existing resources. The ERM methodology is further described in the draft IGP Grid Needs Assessment & Solution Evaluation Methodology deliverable.[3]

2.3. Low Renewable Generation Analysis

The objective of the low renewable generation analysis is to test the resilience of the Grid Needs portfolio in poor weather conditions. Using the PPA Contract Extensions Scenario, the plan was stress tested for the years 2025-2029 using 10 forced outage loops on thermal generating units and a minimum production profile for PV, wind, and hydro resources based on the lowest hourly production observed in historical production and past weather years.

2.4. Transmission Needs Analysis

The transmission needs analysis is provided in three key sections: (1) a high-level system security assessment, (2) a high-level Grid Needs analysis for Stage 3 RFP, and (3) interconnection options for Stage 3 RFP procurements. The high-level system security assessment is performed based on the Stage 2 RFP interconnection requirements studies and other internal studies that have been completed to date. The high-level Grid Needs analysis for Stage 3 is an additional analysis that identifies potential near-term steady-state needs based on the modeled Grid Needs portfolios. Lastly, the interconnection options analysis will identify existing substation sites for interconnection and provide the approximate available capacity at the site while also identifying potential exclusion areas which consider geographic diversity of generation resources.

3. Key Inputs to the Grid Needs Analysis

The inputs used in this analysis are briefly described below.

[3] See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/solution_evaluation_and_optimization/20210330_wg_seo_deliverable_draft.pdf, Appendix C, page 49

3.1. Sales Forecast

Hawaiian Electric's July 2020 sales forecast was utilized and provided in the March 30, 2021 draft IGP Inputs and Assumptions deliverable.[4] The July 2020 sales forecast accounts for the forecasted impacts due to COVID-19.

3.2. Fuel Price Forecast

Hawaiian Electric's March 2020 fuel price forecast was utilized for the analysis and provided in the March 30, 2021 draft IGP Inputs and Assumptions deliverable.[5] The forecast was based on the Brent forecast provided by Facts Global Energy.

3.3. Resource Costs

The resource costs used to develop the resource plans provided in this analysis were provided in the March 30, 2021 draft IGP Inputs and Assumptions deliverable.[6] Solar, wind, and battery energy storage system costs were provided by IHS Markit. Synchronous condenser costs were provided by Siemens. Geothermal and biomass cost were provided by the National Renewable Energy Laboratory ("NREL").

3.4. Regulating Reserve

The IGP regulating reserve methodology is described in the March 30, 2021 draft IGP Grid Needs Assessment and Solution Evaluation Methodology deliverable.[7] This analysis included both the 1-minute and 20-minute regulating reserve requirements.

3.5. Near-Term Fossil Generating Unit Status

To comply with Federal regional haze rules, the Hawai'i Department of Health's draft proposed state implementation plan will require the addition of selective catalytic reduction and combustion controls for units Hill 5 and Hill 6 no later than the end of 2027. It will also require use of ultra-low sulfur fuel at Hill 5, Hill 6 and the Puna Steam unit starting in 2025. For the sole purpose of the Grid Needs Assessment, the Company evaluated the system Grid Needs assuming Hill 5 and 6 would not be dispatched starting in 2027. Additionally, the Grid Needs Assessment assumed that Puna Steam would not be dispatched from 2025. This does not imply that the Company will retire these units in the years in which the model does not dispatch them. Actual

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[4] See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf, Appendix D, page 153

[5] See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf, page 42

[6] https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20210330_wg_fa_deliverable_draft.pdf, Appendix A, page 100

[7] See https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/solution_evaluation_and_optimization/20210330_wg_seo_deliverable_draft.pdf, Appendix C, page 52

retirement decisions are operational decisions that will be made at a later date based on a number of factors, including whether sufficient resources have been acquired and are in service, ancillary services provided by these generators have been sufficiently replaced, and after consideration for reliability and resilience factors, among others.

3.6. Scenario Analysis

In developing the proposed RFP targets, several scenarios were examined to help identify the range of potential Grid Needs under different assumptions.

- Status Quo – Uses IGP planning assumptions with Stage 1 and 2 renewable projects, CBRE Phase 1 and 2, and GSPA contracts in-service. All other existing power purchase agreements ("PPAs") are assumed to terminate at the end of their current contract terms, except for PGV which is assumed to continue through the planning horizon.

- Scenario 1: Base Scenario – The reference case using the IGP planning assumptions where new resources are allowed to be built. The Base resource plan assumes PGV remains under its existing contract at 38 MW through the model period. PPAs for the Hamakua Energy Partners ("HEP") facility and existing variable renewable projects are assumed to terminate at the end of their contract term to allow for their capacity to be re-optimized through RESOLVE. The Base Scenario also assumes a managed charging profile for electric vehicles.

- Scenario 2: PPA Contract Extensions Scenario – Using the Base as a reference, this scenario assumes that the 8 MW PGV expansion is in service in 2024 under the proposed amended contract, for a total of 46 MW. PPAs for existing variable renewable projects are assumed to continue through the planning horizon. These projects include Hawi Wind (10.5 mw), Wailuku River Hydro (11.5 MW), and Pakini Nui Wind (20.5 MW). The PPA for the HEP facility is still assumed to terminate at the end of its term.

- Scenario 3: PGV and Hu Honua Scenario – Using the Base as a reference, this scenario assumes that the 8 MW PGV expansion from 38 to 46 MW is in service in 2024 under the proposed amended contract and Hu Honua is in service in 2022.

- Scenario 4: High Electrification Scenario – Using the Base as a reference, the electric vehicle layer of the sales forecast was increased by 30%.

3.6.1. Planned Resource Assumptions

The planned resource assumptions that are assumed in the planning scenarios are shown in Figure 3-1.

Figure 3-1: Planned Resource Assumptions for Scenarios

Year	Status Quo	Scenario 1: Base	Scenario 2: PPA Contract Extensions	Scenario 3: PGV and Hu Honua	Scenario 4: High Electrification
2021	38 MW PGV In-service 10.5 MW Hawi Wind In-service 12.1 MW Wailuku Hydro In-service 20.5 MW Pakini Nui Wind In-service 0.75 MW CBRE Phase 1 In-service 2.24 MW FFR In-service 1.21 MW Load Build In-service 1.63 MW Load Reduce In-service	38 MW PGV In-service 10.5 MW Hawi Wind In-service 12.1 MW Wailuku Hydro In-service 20.5 MW Pakini Nui Wind In-service 0.75 MW CBRE Phase 1 In-service 2.24 MW FFR In-service 1.21 MW Load Build In-service 1.63 MW Load Reduce In-service	38 MW PGV In-service 10.5 MW Hawi Wind In-service 12.1 MW Wailuku Hydro In-service 20.5 MW Pakini Nui Wind In-service 0.75 MW CBRE Phase 1 In-service 2.24 MW FFR In-service 1.21 MW Load Build In-service 1.63 MW Load Reduce In-service	38 MW PGV In-service 10.5 MW Hawi Wind In-service 12.1 MW Wailuku Hydro In-service 20.5 MW Pakini Nui Wind In-service 0.75 MW CBRE Phase 1 In-service 2.24 MW FFR In-service 1.21 MW Load Build In-service 1.63 MW Load Reduce In-service	38 MW PGV In-service 10.5 MW Hawi Wind In-service 12.1 MW Wailuku Hydro In-service 20.5 MW Pakini Nui Wind In-service 0.75 MW CBRE Phase 1 In-service 2.24 MW FFR In-service 1.21 MW Load Build In-service 1.63 MW Load Reduce In-service
2022	10.5 MW Hawi Wind Removed 4.54 MW FFR In-service 2.45 MW Load Build In-service 3.3 MW Load Reduce In-service	10.5 MW Hawi Wind Removed 4.54 MW FFR In-service 2.45 MW Load Build In-service 3.3 MW Load Reduce In-service	4.54 MW FFR In-service 2.45 MW Load Build In-service 3.3 MW Load Reduce In-service	10.5 MW Hawi Wind Removed 4.54 MW FFR In-service 2.45 MW Load Build In-service 3.3 MW Load Reduce In-service Hu Honua In-service (4/2022)	10.5 MW Hawi Wind Removed 4.54 MW FFR In-service 2.45 MW Load Build In-service 3.3 MW Load Reduce In-service
2023	30 MW / 120 MWH Hale Kuawehi Solar In-service 30 MW / 120 MWH AES Waikoloa Solar In-service	30 MW / 120 MWH Hale Kuawehi Solar In-service 30 MW / 120 MWH AES Waikoloa Solar In-service	30 MW / 120 MWH Hale Kuawehi Solar In-service 30 MW / 120 MWH AES Waikoloa Solar In-service	30 MW / 120 MWH Hale Kuawehi Solar In-service 30 MW / 120 MWH AES Waikoloa Solar In-service	30 MW / 120 MWH Hale Kuawehi Solar In-service 30 MW / 120 MWH AES Waikoloa Solar In-service

	12 MW / 12 MWH Keahole BESS In-service 5.87 MW FFR In-service 3.17 MW Load Build In-service 4.27 MW Load Reduce In-service	12 MW / 12 MWH Keahole BESS In-service 5.87 MW FFR In-service 3.17 MW Load Build In-service 4.27 MW Load Reduce In-service	12 MW / 12 MWH Keahole BESS In-service 5.87 MW FFR In-service 3.17 MW Load Build In-service 4.27 MW Load Reduce In-service	12 MW / 12 MWH Keahole BESS In-service 5.87 MW FFR In-service 3.17 MW Load Build In-service 4.27 MW Load Reduce In-service	12 MW / 12 MWH Keahole BESS In-service 5.87 MW FFR In-service 3.17 MW Load Build In-service 4.27 MW Load Reduce In-service
2024	12.1 MW Wailuku Hydro Removed 60 MW / 240 MWH Puakō Solar In-service	12.1 MW Wailuku Hydro Removed 60 MW / 240 MWH Puakō Solar In-service	46 MW PGV In-service 60 MW / 240 MWH Puakō Solar In-service	12.1 MW Wailuku Hydro Removed 46 MW PGV In-service 60 MW / 240 MWH Puakō Solar In-service	12.1 MW Wailuku Hydro Removed 60 MW / 240 MWH Puakō Solar In-service
2025	30 MW CBRE Phase 2 In-Service	30 MW CBRE Phase 2 In-Service	30 MW CBRE Phase 2 In-Service	30 MW CBRE Phase 2 In-Service	30 MW CBRE Phase 2 In-Service
2026	5.87 MW FFR Removed 3.17 MW Load build Removed 4.27 MW Load reduce Removed	5.87 MW FFR Removed 3.17 MW Load build Removed 4.27 MW Load reduce Removed		5.87 MW FFR Removed 3.17 MW Load build Removed 4.27 MW Load reduce Removed	5.87 MW FFR Removed 3.17 MW Load build Removed 4.27 MW Load reduce Removed
2028	20.5 MW Pakini Nui Wind Removed	20.5 MW Pakini Nui Wind Removed		20.5 MW Pakini Nui Wind Removed	20.5 MW Pakini Nui Wind Removed
2031	60 MW HEP Removed	60 MW HEP Removed	60 MW HEP Removed	60 MW HEP Removed	60 MW HEP Removed

4. Resource Grid Needs Analysis

This section describes the resulting Grid Needs that were optimized in RESOLVE and operations validated in PLEXOS. Consistent with the IGP process and Commission direction for an all-resource RFP, the Grid Needs are presented as technology-neutral for the various grid services that are needed under each of the four scenarios modeled. Near-term resource Grid Needs are shown for the years 2025 and 2030.

4.1. Summary of 2025 Grid Needs Portfolio

Shown below in Figure 4-1 is a summary of the 2025 Grid Needs for the various scenarios.

Figure 4-1: Summary of 2025 Grid Needs Provided by Proxy Resources in the Various Scenarios

Grid Need	Year	Scenario 1: Base	Scenario 2: PPA Contract Extensions	Scenario 3: PGV and Hu Honua	Scenario 4: High Electrification
Energy, GWh	2025	265.3	206.2	299.9	269.8
Load Reduce, MW	2025	56.2	57.7	65.5	69.3
Load Reduce, Calls/Year	2025	67	55	39	16
Load Reduce, Hours/Call	2025	2.9	2.1	2.8	1.8
Load Build, MW	2025	13.5	16.6	9.9	14.5
Load Build, Calls/Year	2025	198	148	218	208
Load Build, Hours/Call	2025	1.1	1.1	1.1	1.1
Up Reg, MW	2025	61.2	47.3	43.8	61.3
Up Ramp, MW	2025	28.5	28.9	28.6	28.5
Down Reg, MW	2025	22.4	22.2	22.8	24.9
Down Ramp, MW	2025	16.0	16.6	16.1	17.7
ERM, MW	2025	0.0	0.0	0.0	0.0

As shown in Figure 4-1 above, the 2025 Grid Needs under the various scenarios were similar, even under the higher EV load. Extending the existing PPA contracts in Scenario 2 reduces some of the Grid Needs slightly. As noted elsewhere in this Report, the identified Grid Needs are not required to be in-service by 2025 for reliability reasons. Sourcing the Grid Needs through a competitive procurement should provide sufficient flexibility in the commercial operations date to allow for other technologies that may take longer develop but provide diversification, resilience, or other benefits.

In a scenario where existing PPA contracts are extended as in Scenario 2, and the amended PGV PPA and Hu Honua are approved and reach commercial operations, the Grid Needs would likely be significantly reduced. In other words, adding the expanded PGV and Hu Honua generation to Scenario 2, would likely meet most of the needs identified in Scenario 2.

Figure 4-2 below provides a summary of renewable portfolio standard and renewable energy utilization for each of the scenarios.

Figure 4-2: Summary of RPS and Energy Utilization based on 2025 Grid Needs

RPS and Variable Renewable Generation Utilized	RPS (% of sales)	RPS-A (% of generation)	Variable Renewable Generation Utilized for Energy (GWH)	Variable Renewable Generation Utilized for Energy (%)
Scenario 0: Status Quo	104.5%	79.5%	562.6	97%
Scenario 1: Base	119.3%	90.5%	732.6	81%
Scenario 2: PPA Contract Extensions	121.7%	92.1%	804.4	91%
Scenario 3: PGV and Hu Honua	121.7%	92.3%	759.6	83%
Scenario 4: High Electrification	119.2%	90.5%	735.1	81%

4.2. Summary of 2030 Grid Needs Portfolio

Shown below in Figure 4-3 is a summary of the Grid Needs in 2030 for the various scenarios. For energy, regulating reserve, ramp reserve, and ERM, the needs are incremental to 2025 Grid Needs. For load build and load reduce, the needs are cumulative, as the assumption is these needs would be for a 5-year term.

Figure 4-3: Summary of 2030 Grid Needs Provided by Proxy Resources in the Various Scenarios

Grid Need	Year	Scenario 1: Base	Scenario 2: PPA Contract Extensions	Scenario 3: PGV and Hu Honua	Scenario 4: High Electrification
Energy, GWh	2030	119.4	0.0	6.4	132.6
Load Reduce, MW	2030	108.7	58.3	69.3	110.5
Load Reduce, Calls/Year	2030	68	17	10	67
Load Reduce, Hours/Call	2030	1.3	2.8	2.3	1.5
Load Build, MW	2030	20.8	16.6	10.7	21.4
Load Build, Calls/Year	2030	222	122	224	226
Load Build, Hours/Call	2030	1.2	1.1	1.1	1.2
Up Reg, MW	2030	0.0	3.8	0.2	0.6
Up Ramp, MW	2030	1.5	2.0	1.6	1.6
Down Reg, MW	2030	0.0	0.0	1.5	0.0
Down Ramp, MW	2030	4.9	0.0	1.8	0.2
ERM, MW	2030	95.4	82.6	0.0	103.8

As shown in Figure 4-3 above, extending the existing PPAs in Scenario 2 and the addition of PGV's amended and restated PPA and Hu Honua significantly reduces the Grid Needs. In 2025, there are no ERM needs; however, in 2030, the ERM needs range from 0 MW to 104 MW. The need for ERM in the 2030 timeframe is driven by the assumption that the HEP PPA, the term of which is currently set to expire in 2031, is not extended. New capacity will be needed to replace HEP should the term of its PPA not be extended. Scenario 3 shows that, regardless of the status of HEP, the addition of 8 additional MW capacity from PGV and Hu Honua would provide sufficient ERM capacity needs.

Figure 4-4 below provides a summary of renewable portfolio standard and renewable energy utilization for each of the scenarios.

Figure 4-4: Summary of RPS and Energy Utilization based on 2030 Grid Needs

RPS and Variable Renewable Generation Utilized	RPS (% of sales)	RPS-A (% of generation)	Variable Renewable Generation Utilized for Energy (GWH)	Variable Renewable Generation Utilized for Energy (%)
Scenario 0: Status Quo	99.4%	74.7%	485.3	98%
Scenario 1: Base	133.8%	99.2%	658.0	80%
Scenario 2: PPA Contract Extensions	133.0%	98.3%	865.0	94%
Scenario 3: PGV and Hu Honua	132.8%	98.2%	800.0	94%
Scenario 4: High Electrification	133.4%	99.1%	665.8	80%

4.3. Detailed Grid Needs for Scenario 2: PPA Contract Extensions

Scenario 2 produces a portfolio of Grid Needs if the PGV amended and restated PPA is approved at 46 MW, and existing PPA renewable contracts slated to expire over the near-term are extended. Other scenarios assessed Grid Needs if various uncertainties of existing generating assets were not to reach commercial operations. Based on the summary of Grid Needs, Scenario 2 represents a "least regrets" portfolio of needs that can could be considered as part of future solution sourcing discussions. The following sections provide additional detail of the grid services that are needed in the near-term under Scenario 2.

4.3.1. Illustrative Daily Dispatch

The dispatch of the proxy resource is shown below in for various days in 2028 and 2030, where there is high, average, and low utilization of the incremental proxy resources for energy.

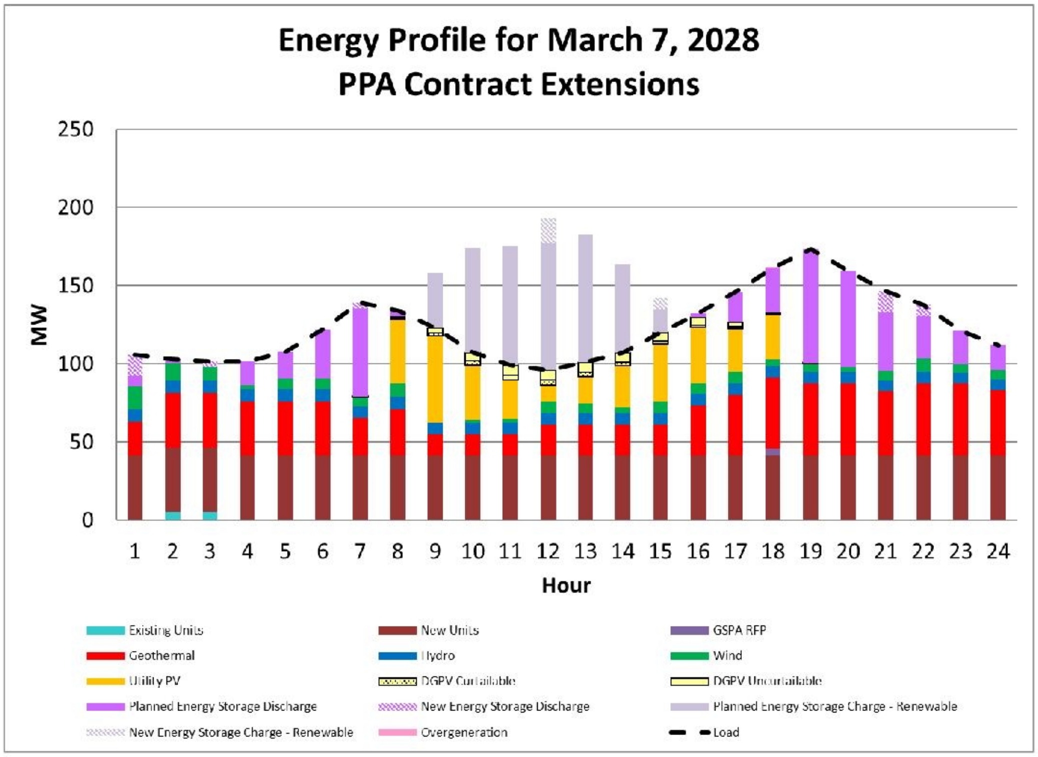


Figure 4-5 Daily Chart – High Utilization of Proxy Resources in 2028

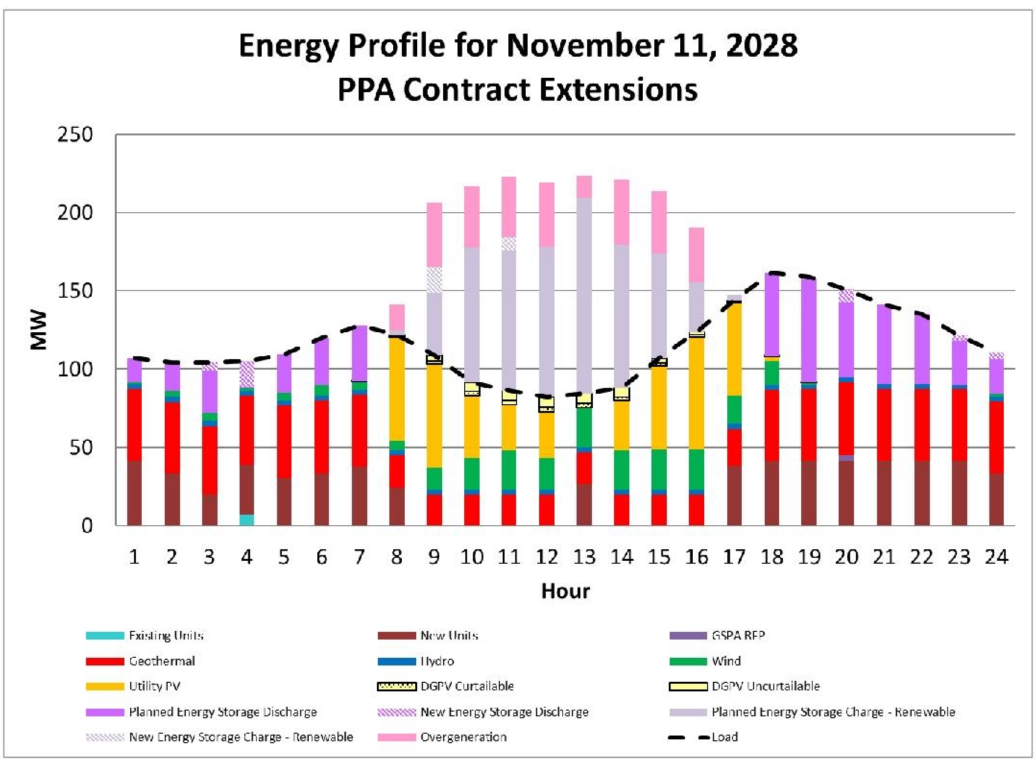


Figure 4-6 Daily Chart – Average Utilization of Proxy Resources in 2028

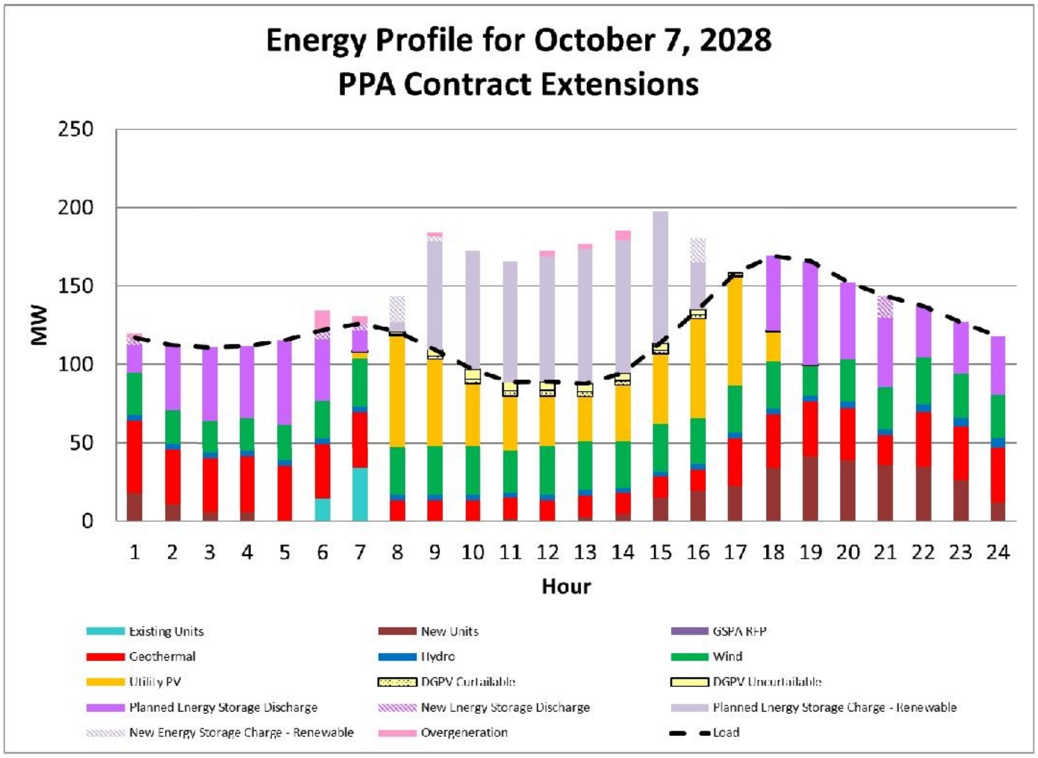


Figure 4-7 Daily Chart – Low Utilization of Proxy Resources in 2028

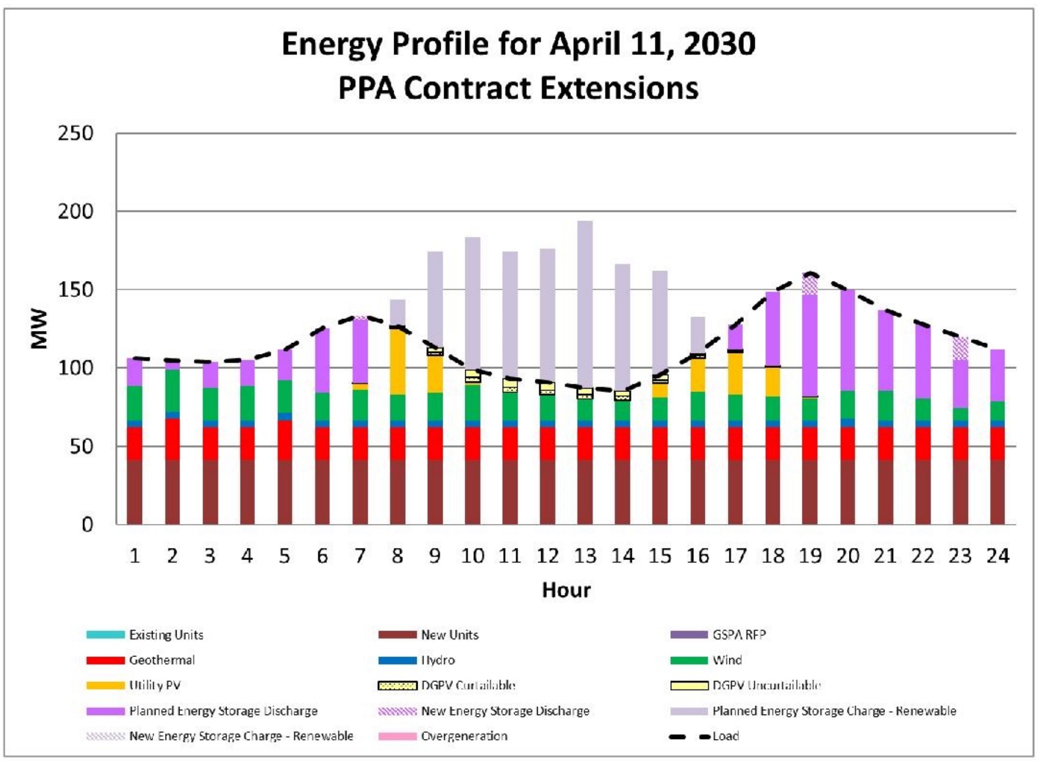


Figure 4-8: Daily Chart – High Utilization of Proxy Resources in 2030

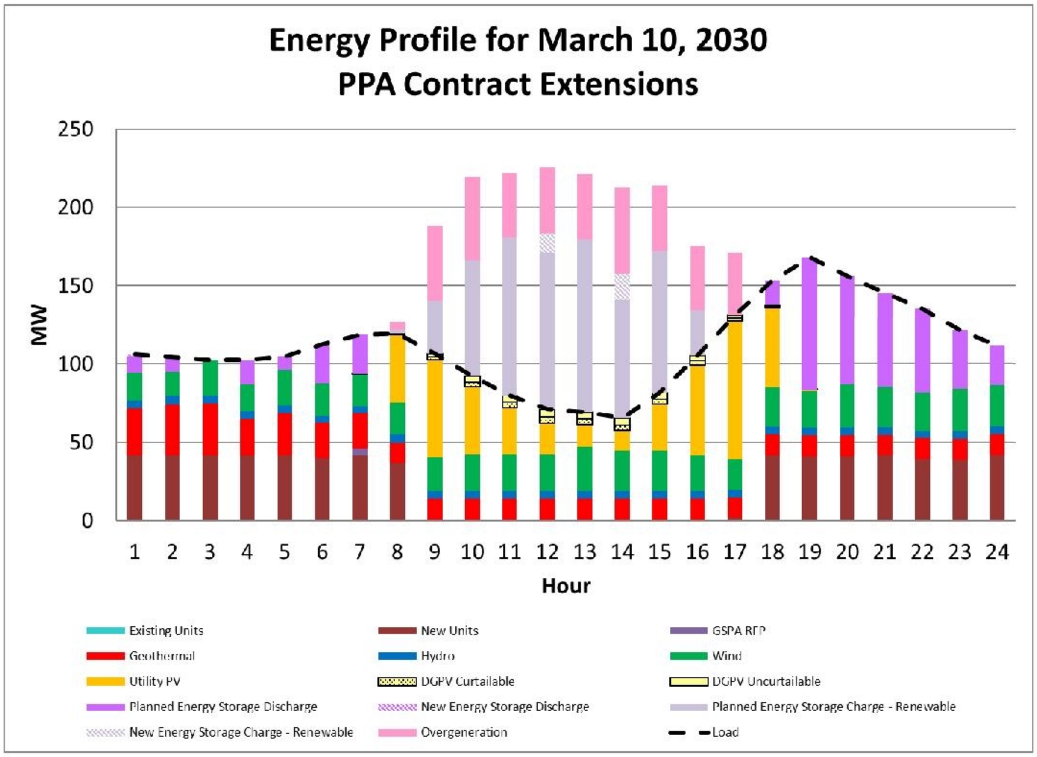


Figure 4-9: Daily Chart – Average Utilization of Proxy Resources in 2030

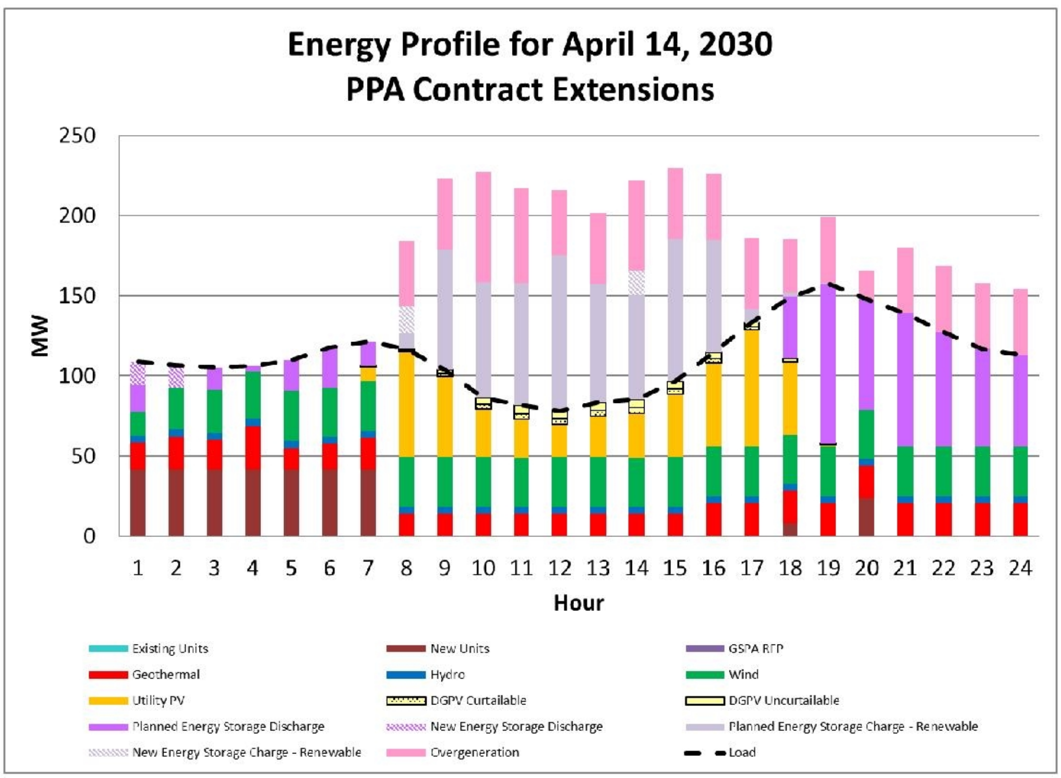


Figure 4-10 Daily Chart – Low Utilization of Proxy Resources in 2030

In Figure 4-5 through Figure 4-10 shown above, New Units represents the proxy resources selected by RESOLVE, which in this case, was Onshore Wind. For the days selected in Figure 4-5 and Figure 4-8, the Onshore Wind had a relatively flat output. While the proxy resource selected by RESOLVE was Onshore Wind, any resource that could meet the needs of the system with similar production profile and resource availability as provided by the proxy resource could be taken into consideration. The following sections provide granular and temporal information on the Grid Needs.

4.3.2. Energy

The hourly requirement for energy is based on the aggregated hourly dispatch of the new resources selected by RESOLVE. The 2025 power need is based on the maximum aggregated hourly power requirement between 2025 and 2029. The 2030 need is based on the maximum between 2030 and 2034.

The annual energy requirement is based on the annual sum of the hourly dispatch of the new resources selected by RESOLVE. The 2025 energy need is based on the maximum annual requirement between 2025 and 2029. The 2030 need is based on the maximum between 2030 and 2034.

The energy need on a monthly and hourly basis is shown below. The 2025 need amount is based on the maximum hourly requirement between 2025 and 2029 and shown in Figure 4-11 through Figure 4-13 is the average energy needs. The 2030 need is based on the maximum between 2030 and 2034 and shown in Figure 4-14 through Figure 4-16.

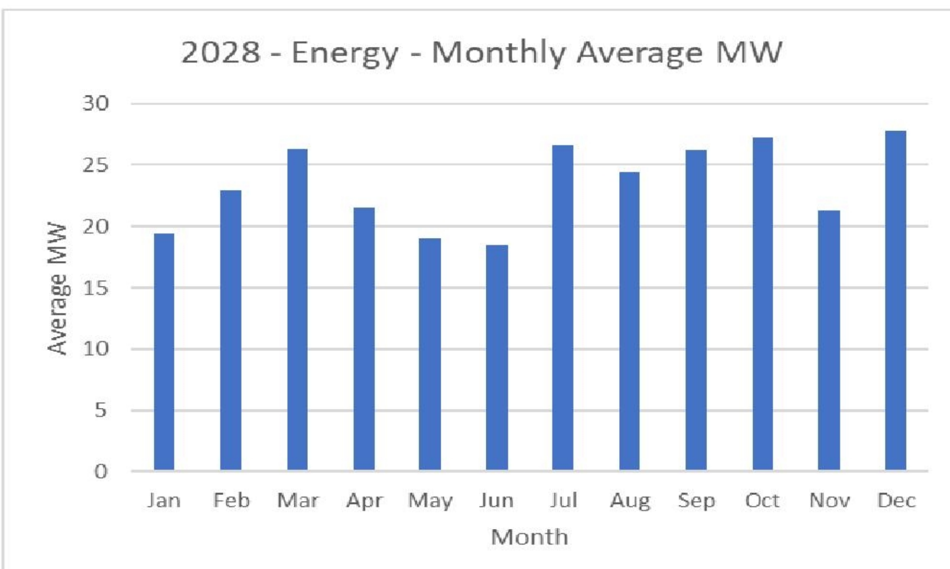


Figure 4-11: Average Dispatch for Energy by Month for 2025 - 2029 Need

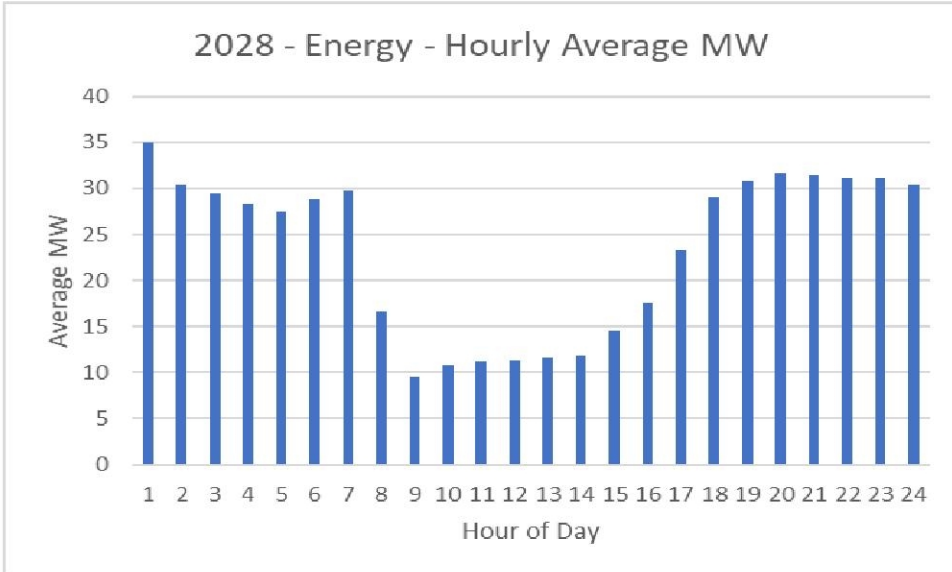


Figure 4-12: Average Dispatch of Energy by Hour for 2025-2029 Need

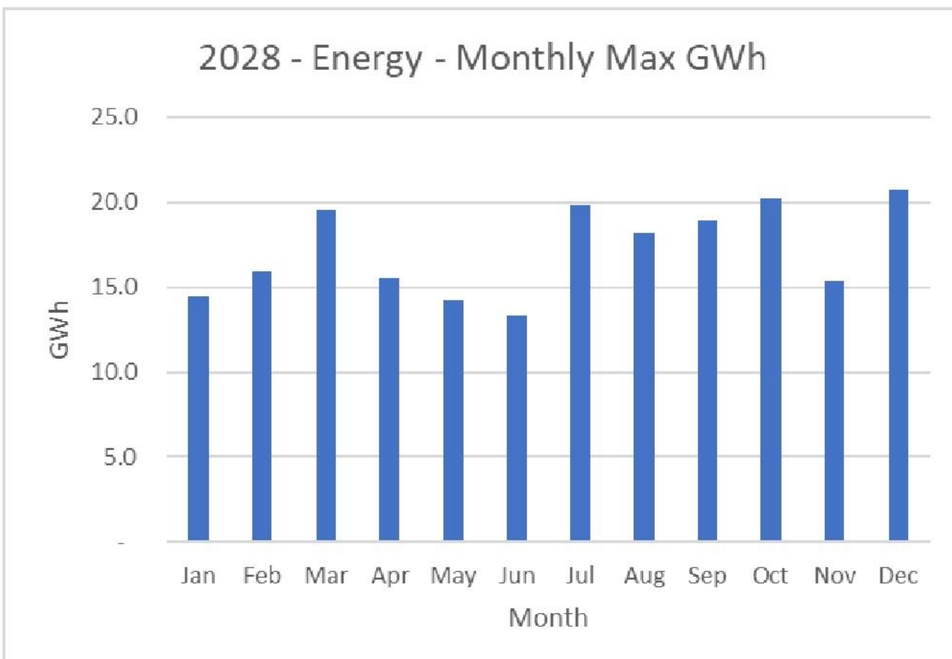


Figure 4-13: Dispatch for Energy by Month for 2025-2029 Need

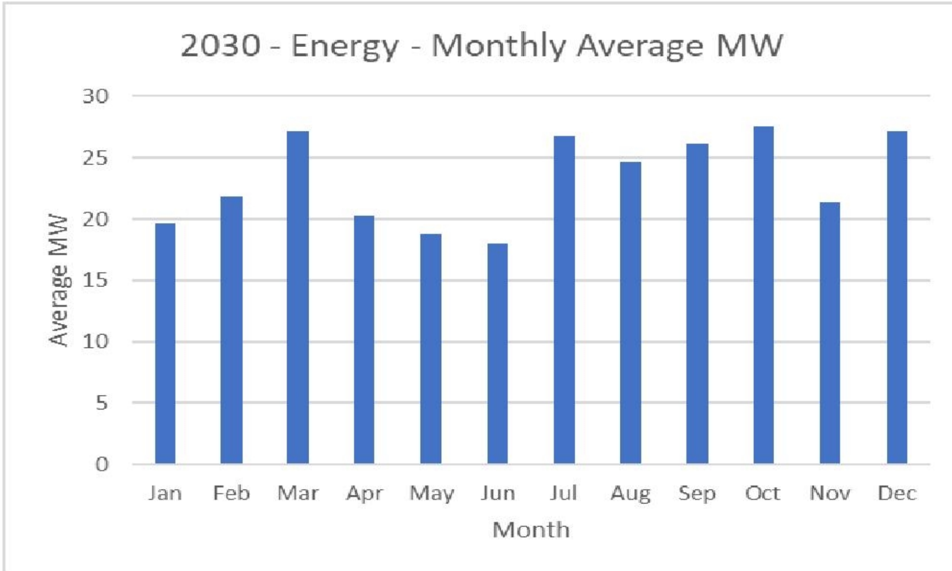


Figure 4-14: Average Dispatch for Energy by Month for 2030-2034 Need

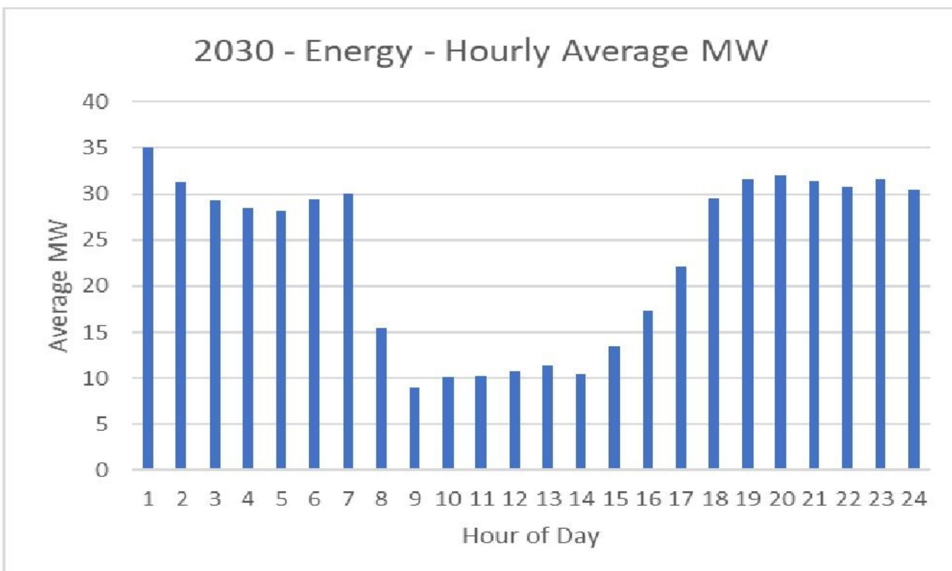


Figure 4-15: Average Dispatch of Energy by Hour for 2030-2034 Need

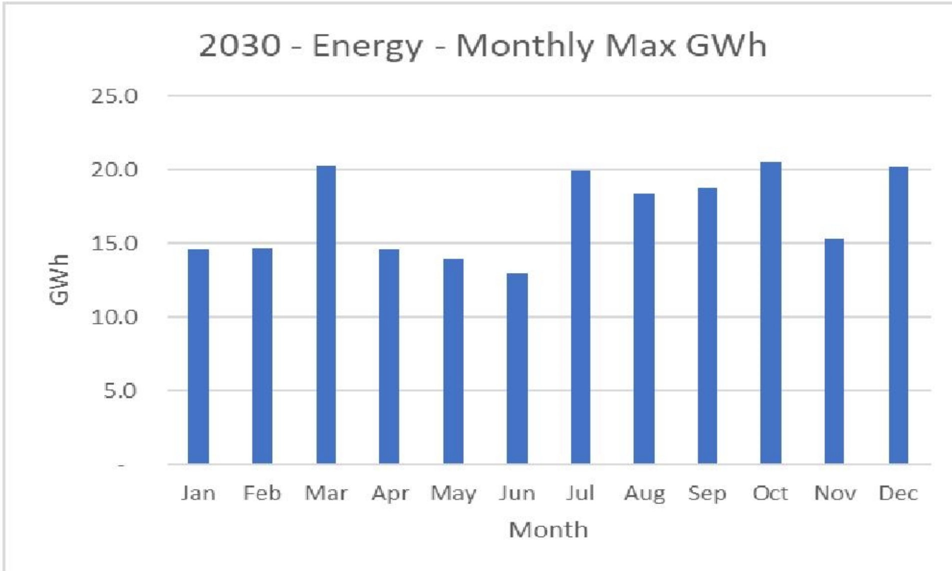


Figure 4-16: Dispatch for Energy by Month for 2030-2034 Need

4.3.3. Load Build

Load build is a subset of the energy grid need and represent opportunities to shift energy throughout the year as described in this section. It is identified during hours where two events occur: (1) the daily available variable renewable energy exceeds a threshold, defined as the annual maximum daily variable renewable energy minus one standard deviation, and (2) the charging of a standalone storage selected by RESOLVE exceeds a threshold, defined as the annual maximum storage load minus one standard deviation.

The 2025 need size, duration, and calls are based on the maximum annual requirement between 2025 and 2029. The 2030 requirement is based on the maximum between 2030 and 2034.

The number of calls for load build on a monthly and hourly basis are shown below in Figure 4-17 and Figure 4-18 for the 2025 need, and Figure 4-19 and Figure 4-20 for the 2030 need.

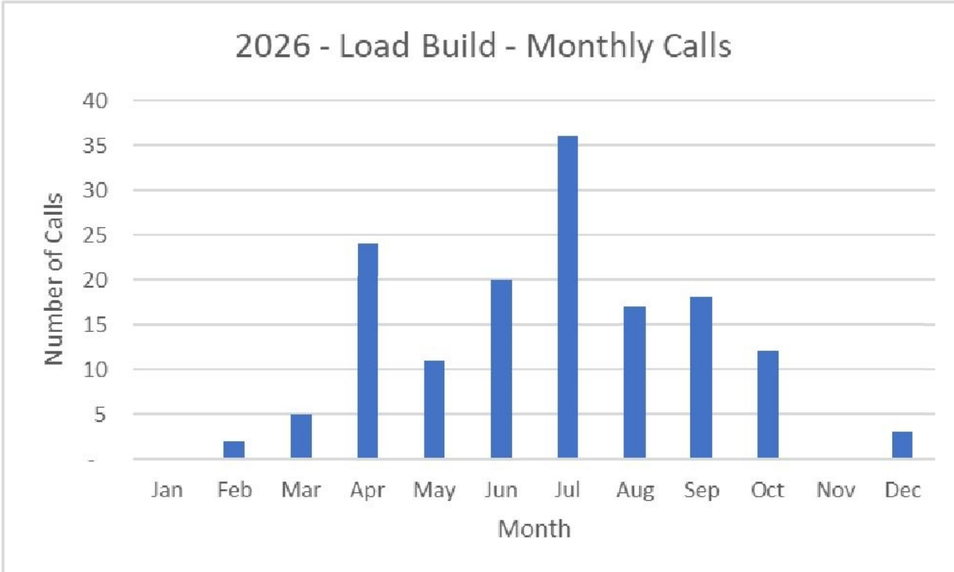


Figure 4-17: Max Number of Calls for Load Build by Month for 2025-2029 Need

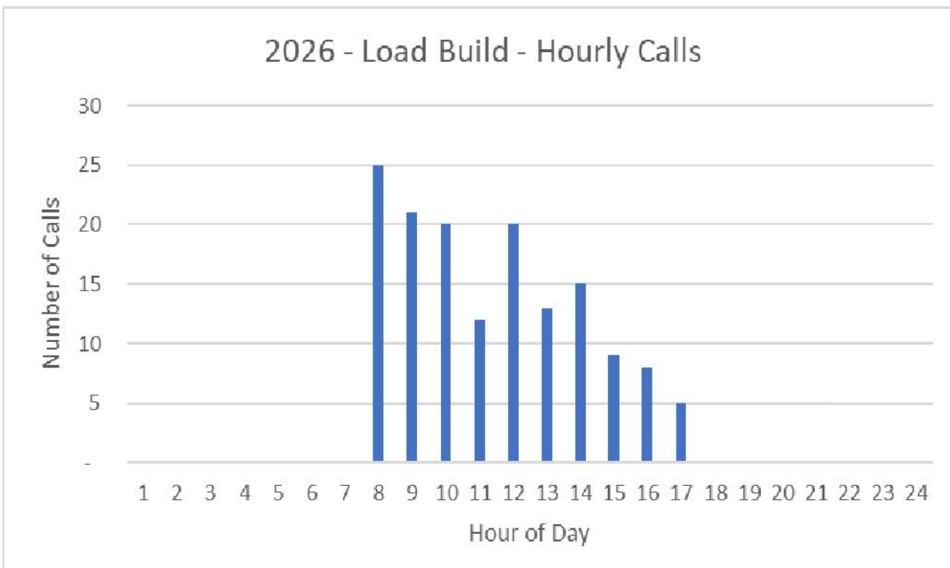


Figure 4-18: Max Number of Calls for Load Build by Hour for 2025-2029 Need

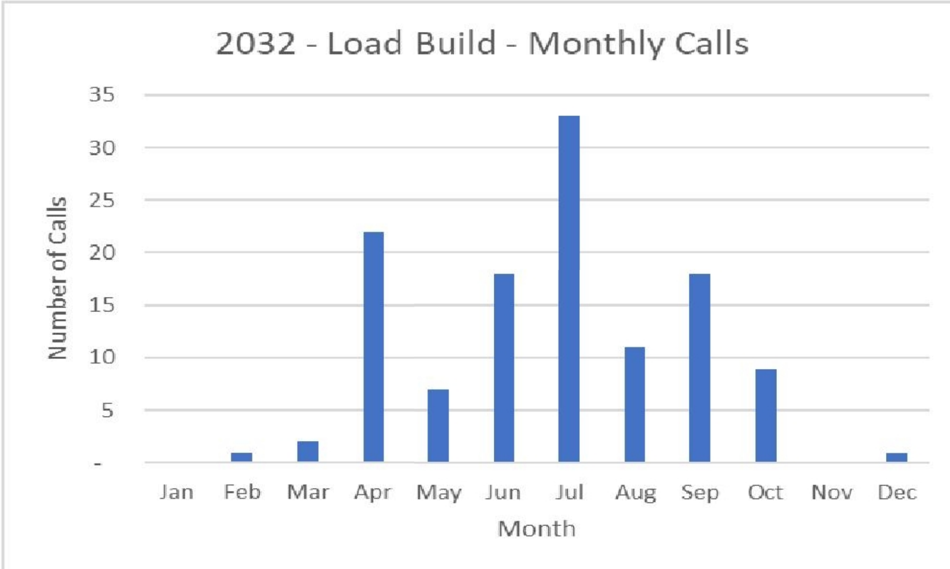


Figure 4-19: Max Number of Calls for Load Build by Month for 2030-2034 Need

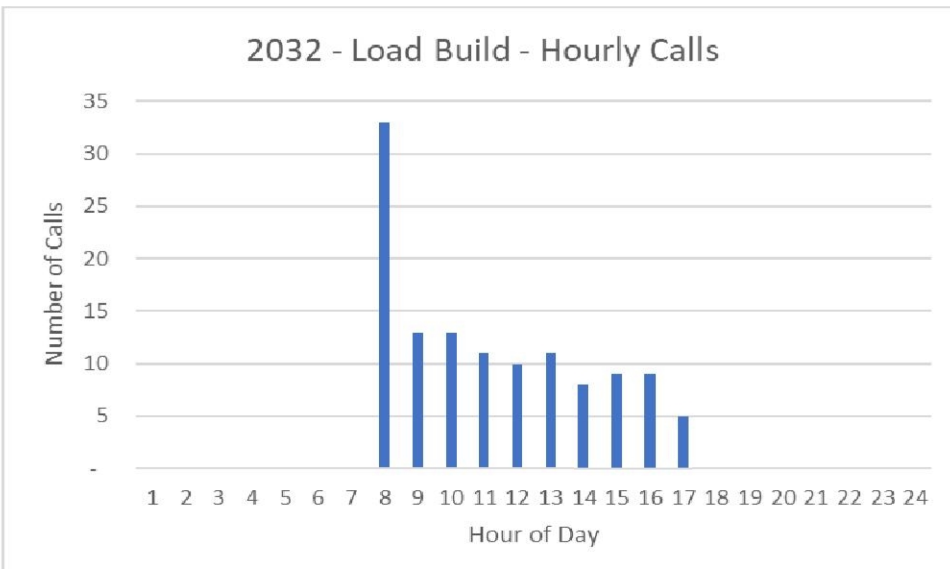


Figure 4-20: Max Number of Calls for Load Build by Hour for 2030-2034 Need

4.3.4. Load Reduce

Load reduce is a subset of the energy grid need and represent opportunities to shift energy throughout the year as described in this section. It is identified during hours where the short-run marginal cost ("SRMC") exceeds a threshold, defined as the annual maximum SRMC of the fossil fuel generators minus one standard deviation. The amount of Load Reduce Service is based on the dispatch of the new resources selected by RESOLVE during the hours where the SRMC exceeds the threshold.

The 2025 need size, duration, and calls are based on the maximum annual requirement between 2025 and 2029. The 2030 requirement is based on the maximum between 2030 and 2034.

The number of calls for the Load Reduce Service on a monthly and hourly basis are shown below in Figure 4-21 and Figure 4-22 for the 2025 need, and Figure 4-23 and Figure 4-24 for the 2030 need.

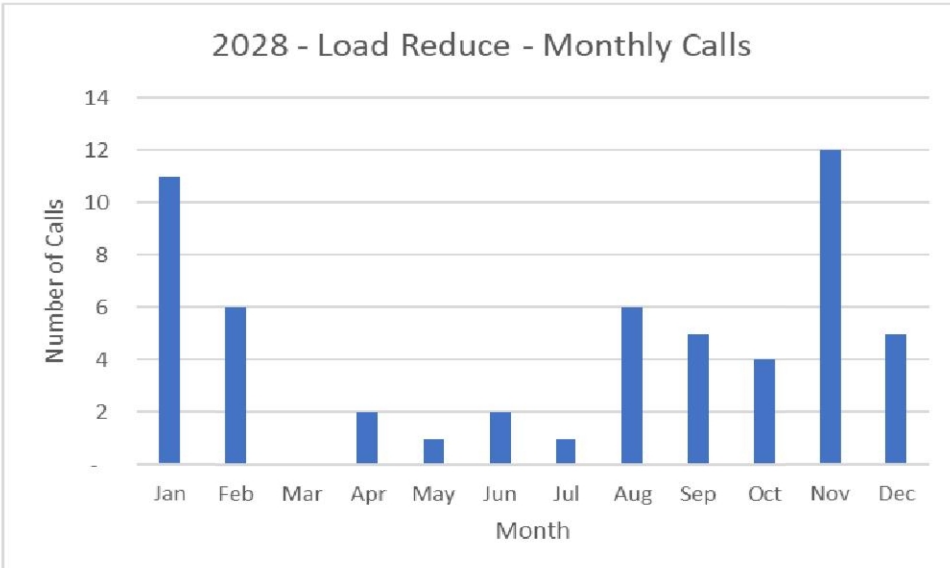


Figure 4-21: Max Number of Calls for Load Reduce by Month for 2025-2029 Need

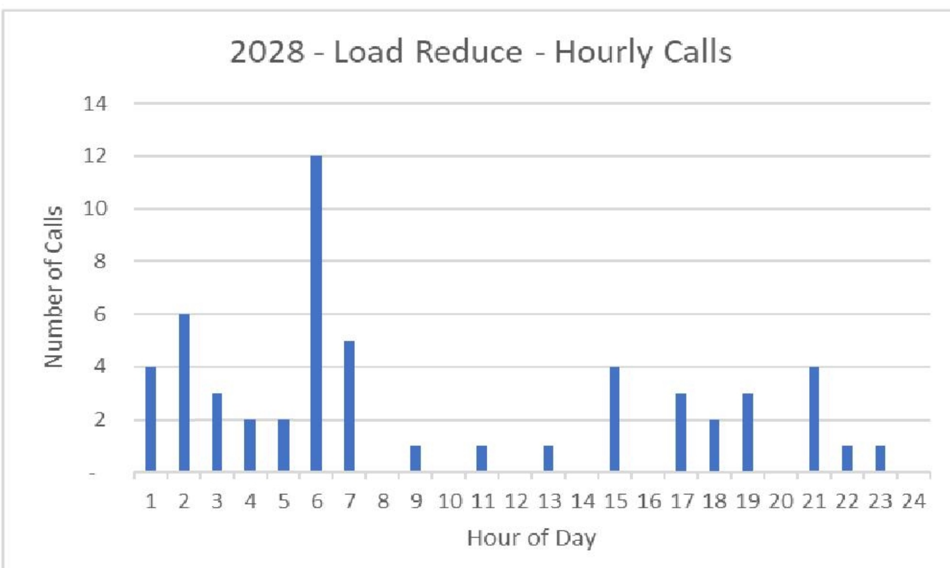


Figure 4-22: Max Number of Calls for Load Reduce by Hour for 2025-2029 Need

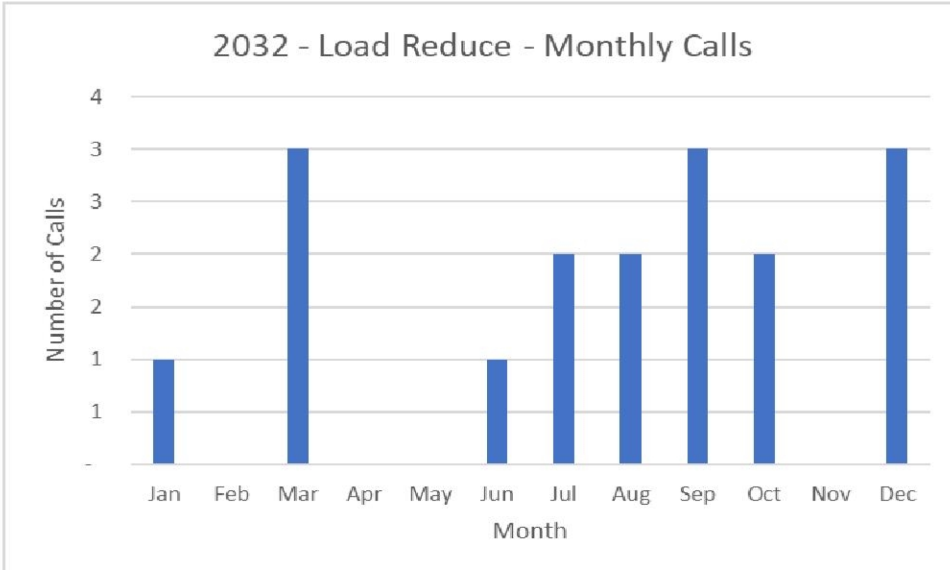


Figure 4-23: Max Number of Calls for Load Reduce by Month for 2030-2034 Need

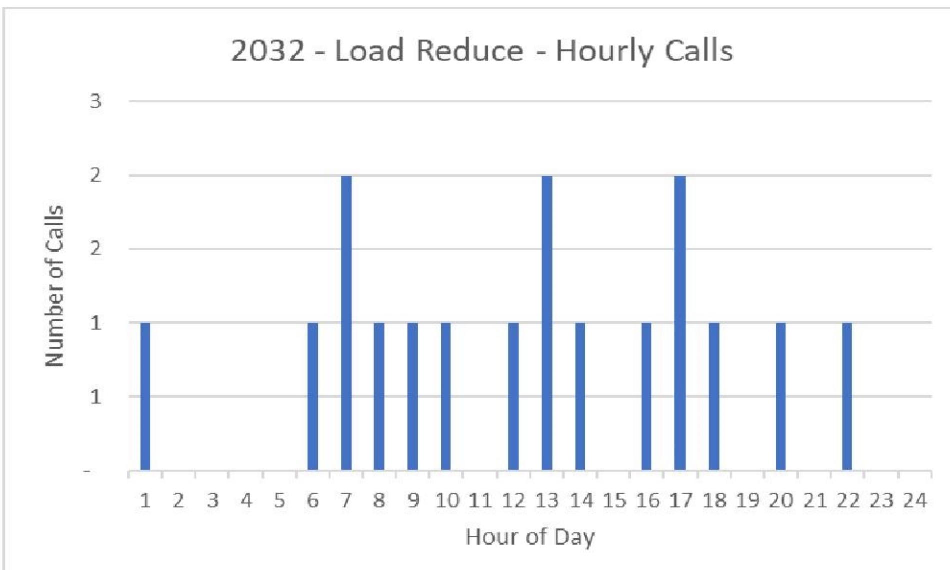


Figure 4-24: Max Number of Calls for Load Reduce by Hour for 2030-2034 Need

4.3.5. Upward and Downward Regulating Reserve and Ramp Reserve

The hourly requirement for the regulating and ramp reserve services is based on the modeled requirement less the amount provided by the planned and existing units. Controllable resources that are subject to Company dispatch may provide regulation and ramp capability to the system. For example, the ability to reduce a resource's output is able to provide downward regulation or ramp reserve and a resource that may be curtailed can contribute to the upward regulation or ramp reserve need. The 2025 need amount is based on the maximum hourly requirement between 2025 and 2029 and shown in Figure 4-25 through Figure 4-32. The 2030 requirement is based on the maximum between 2030 and 2034 and shown in Figure 4-33 through Figure 4-40. This would represent what may need to be available to the operator in any potential hour based on the maximum requirement; actual deployment of reserves will vary from hour to hour.

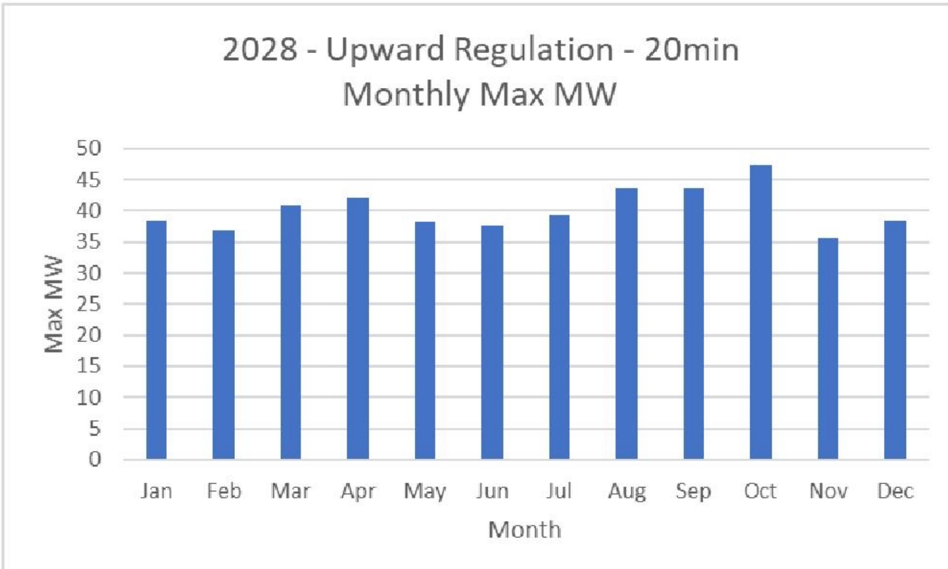


Figure 4-25: Max Dispatch for 20-min Upward Regulating Reserve by Month for 2025-2029 Need

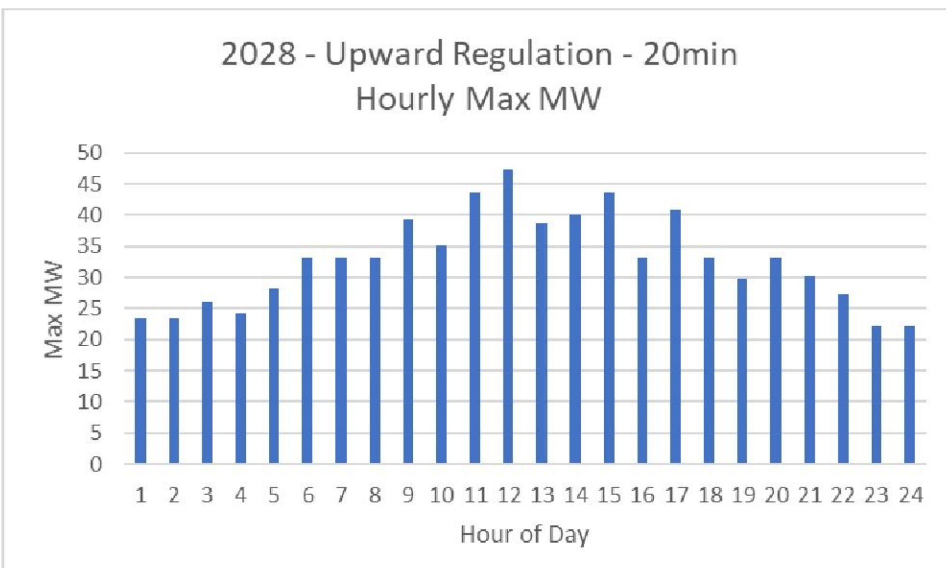


Figure 4-26: Max Dispatch for 20-min Upward Regulating Reserve by Hour for 2025-2029 Need

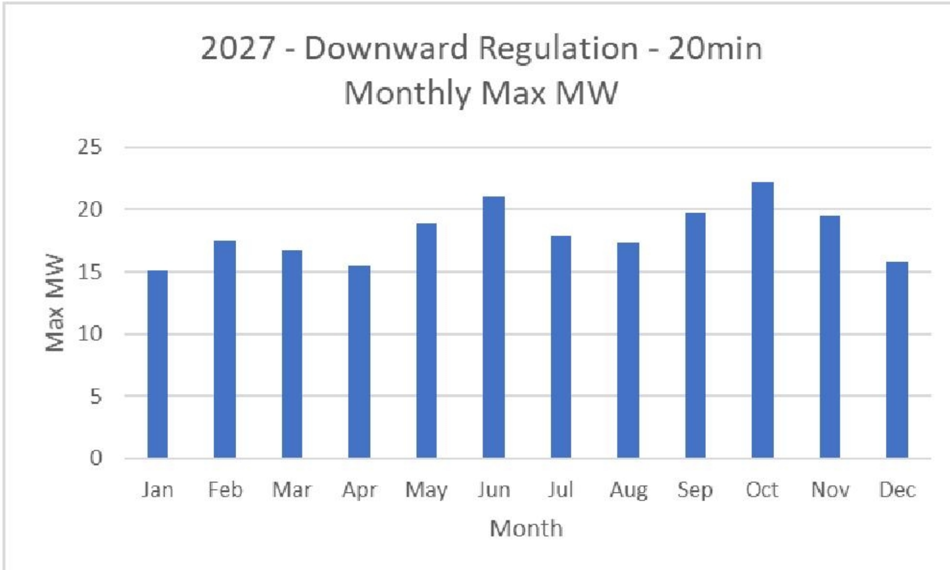


Figure 4-27: Max Dispatch for 20-min Downward Regulating Reserve by Month for 2025-2029 Need

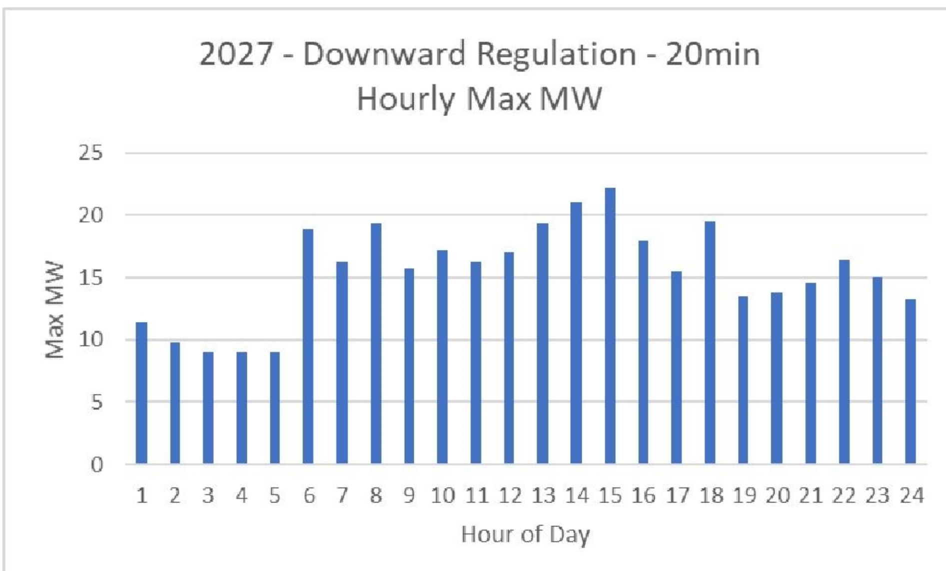


Figure 4-28: Max Dispatch for 20-min Downward Regulating Reserve by Hour for 2025-2029 Need

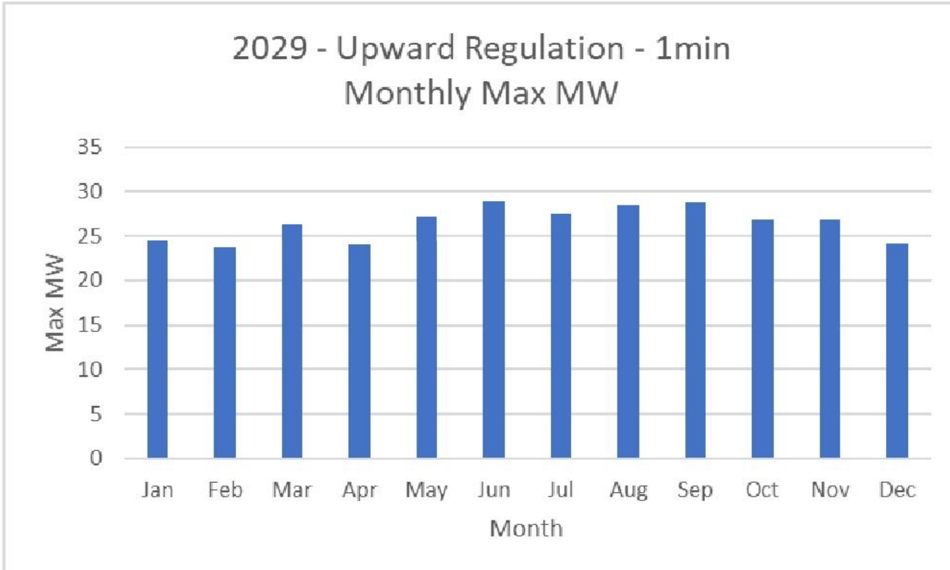


Figure 4-29: Max Dispatch for 1-min Upward Regulating Reserve by Month for 2025-2029 Need

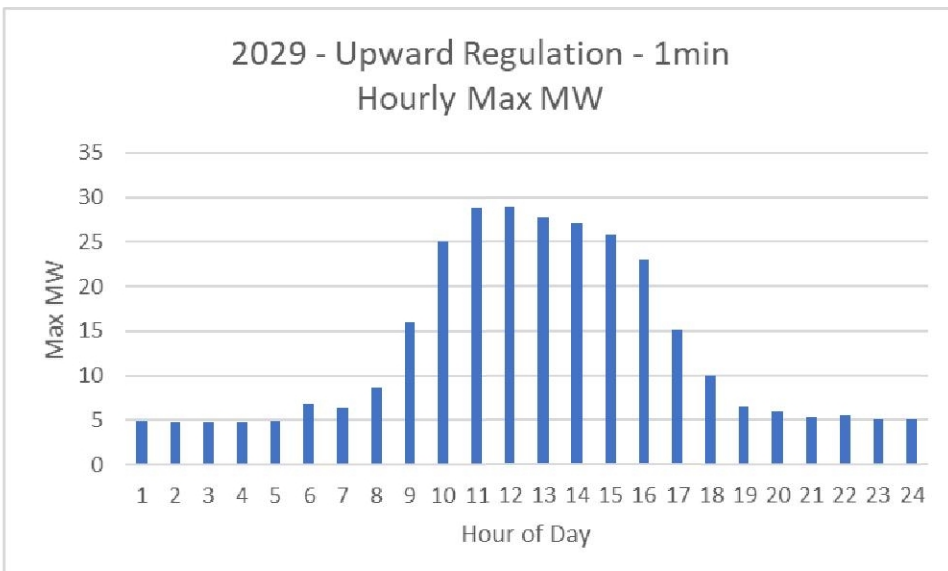


Figure 4-30: Max Dispatch for 1-min Upward Regulating Reserve by Hour for 2025-2029 Need

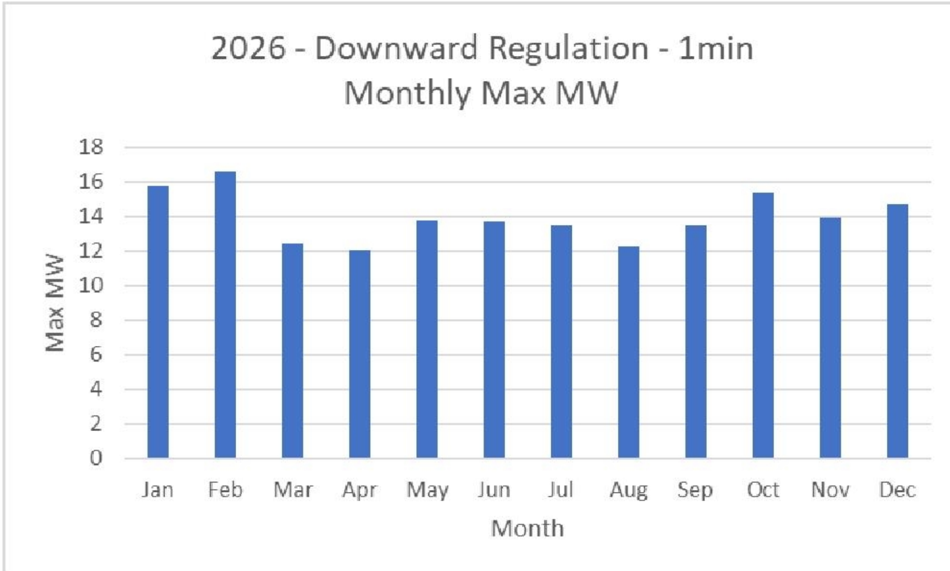


Figure 4-31: Max Dispatch for 1-min Downward Regulating Reserve by Month for 2025-2029 Need

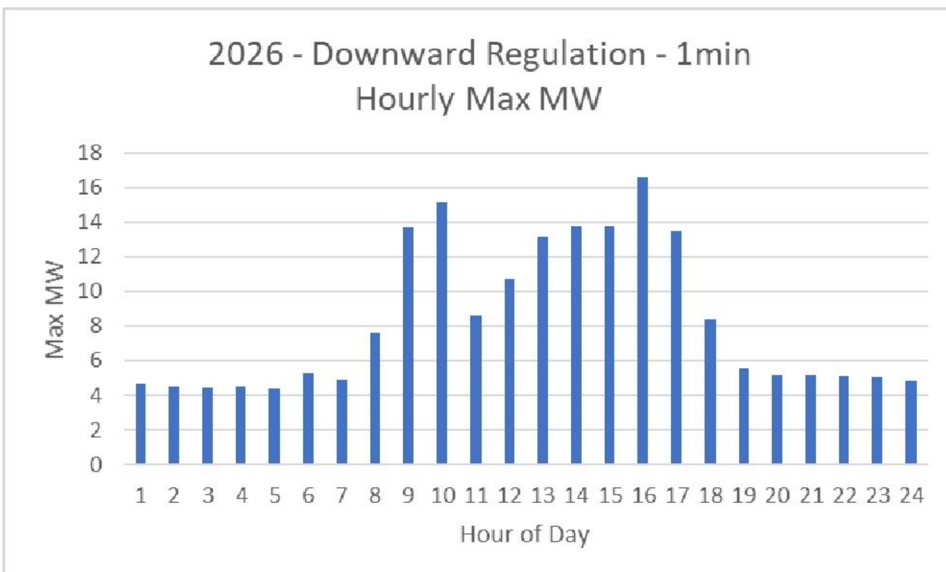


Figure 4-32: Max Dispatch for 1-min Downward Regulating Reserve by Hour for 2025-2029 Need

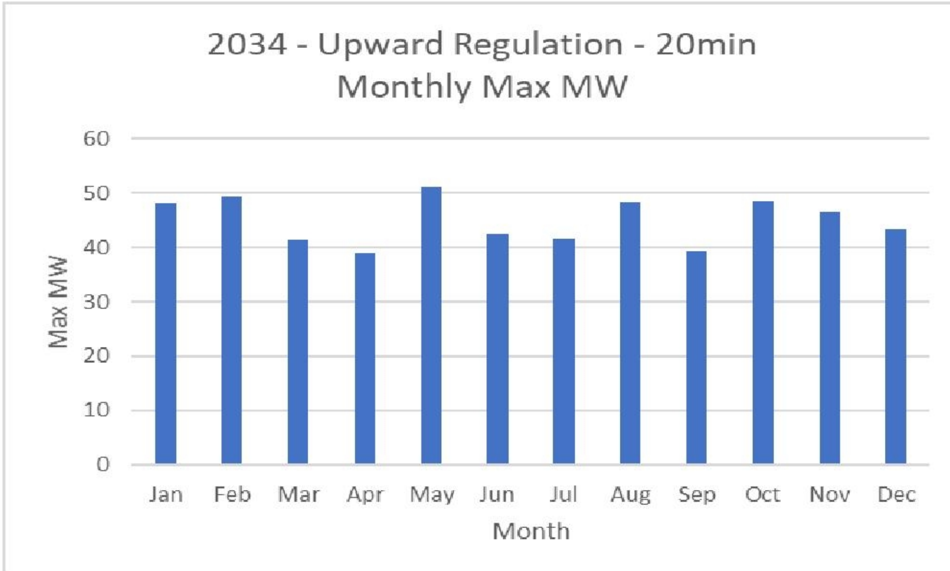


Figure 4-33: Max Dispatch for 20-min Upward Regulating Reserve by Month for 2030-2034 Need

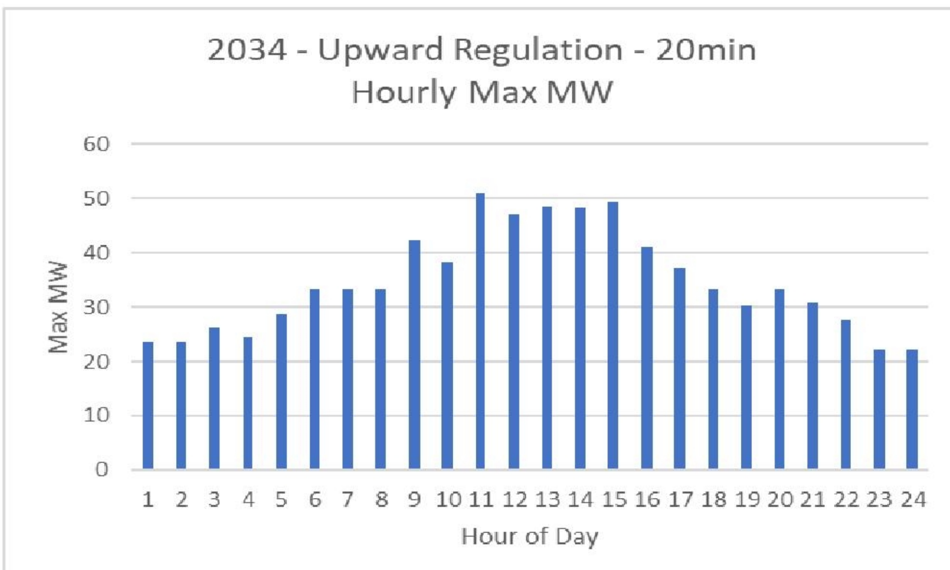


Figure 4-34: Max Dispatch for 20-min Upward Regulating Reserve by Hour for 2030-2034 Need

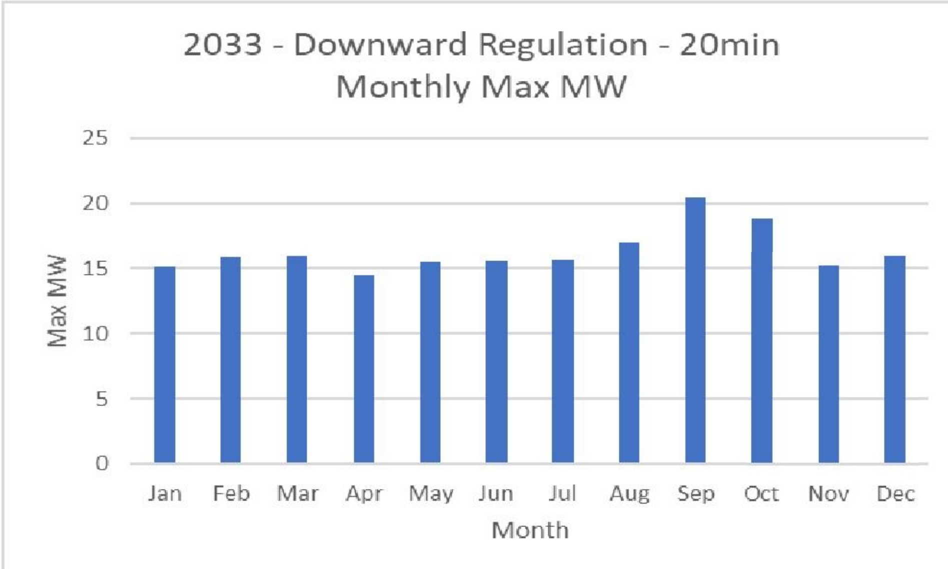


Figure 4-35: Max Dispatch for 20-min Downward Regulating Reserve by Month for 2030-2034 Need

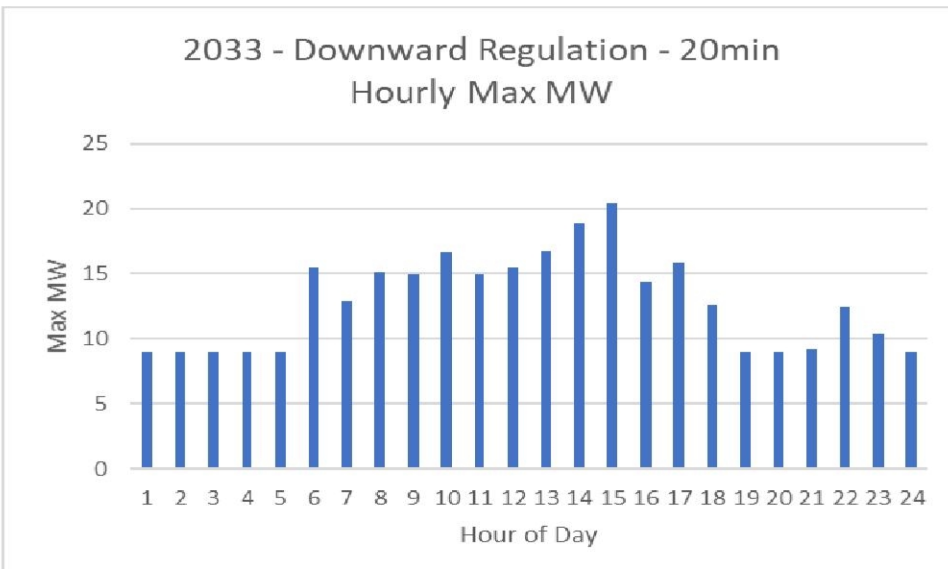


Figure 4-36: Max Dispatch for 20-min Downward Regulating Reserve by Hour for 2030-2034 Need

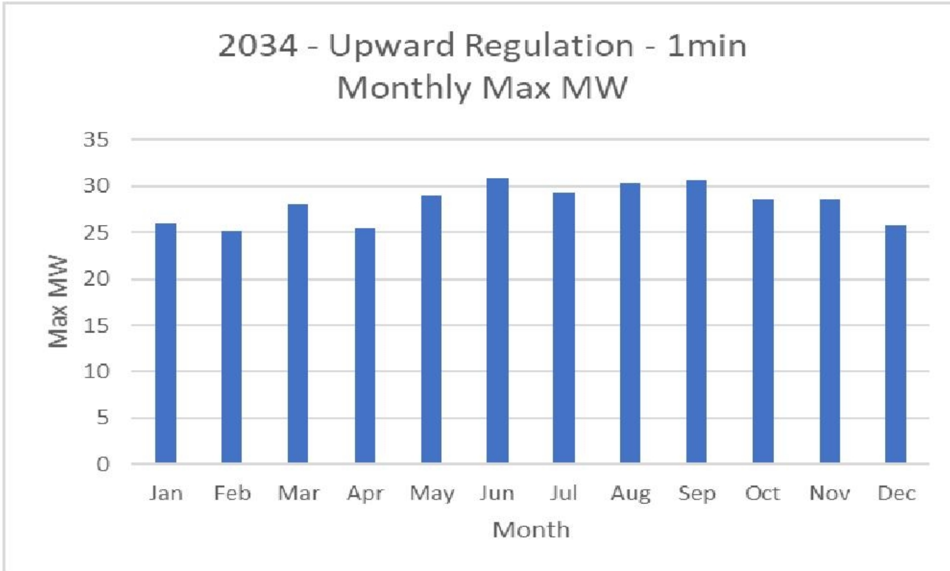


Figure 4-37: Max Dispatch for 1-min Upward Regulating Reserve by Month for 2030-2034 Need

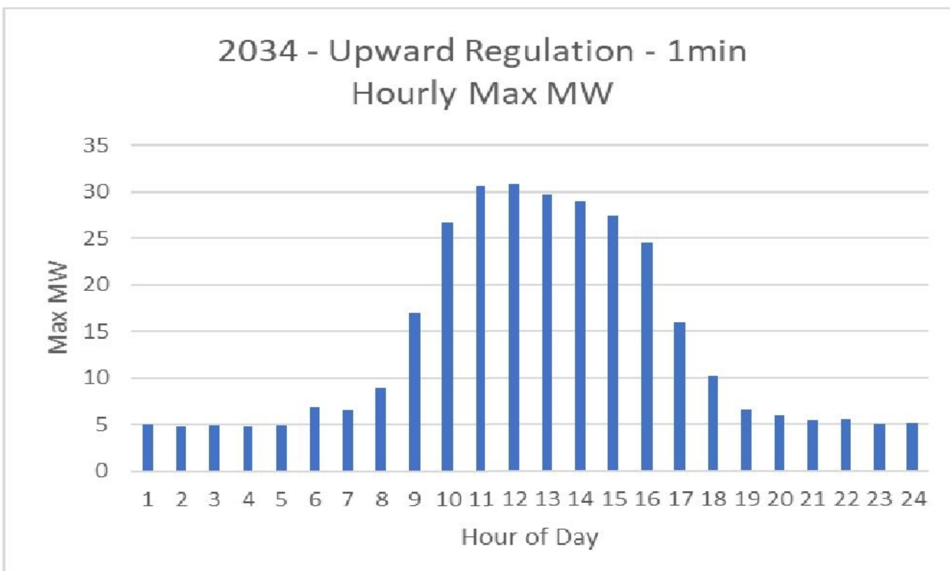


Figure 4-38: Max Dispatch for 1-min Upward Regulating Reserve by Hour for 2030-2034 Need

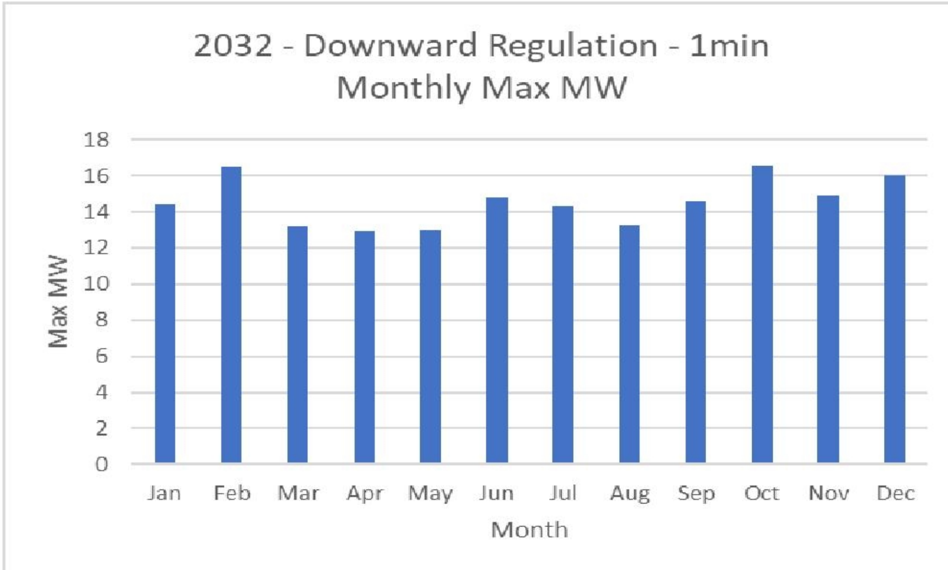


Figure 4-39: Max Dispatch for 1-min Downward Regulating Reserve by Month for 2030-2034 Need

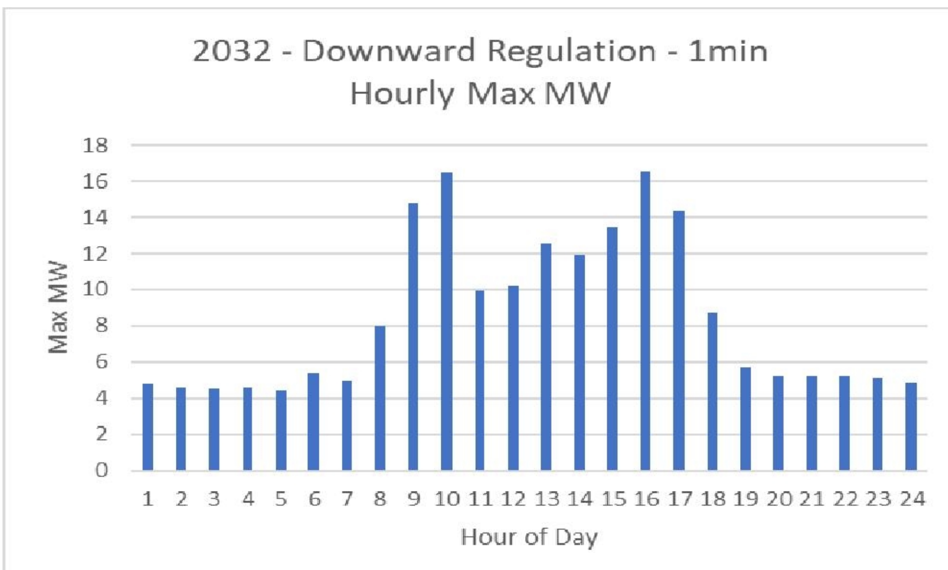


Figure 4-40: Max Dispatch for 1-min Downward Regulating Reserve by Hour for 2030-2034 Need

4.3.6. Capacity for Energy Reserve Margin

The hourly requirement is based on the unserved energy in the ERM analysis. The 2025 target amount is based on the maximum hourly requirement between 2025 and 2029, which is 0 MW, and is shown in Figure 4-41 and Figure 4-42. The 2030 requirement is based on the maximum between 2030 and 2034 and shown in Figure 4-43 and Figure 4-44. This would represent what may need to be available to the operator in any potential hour based on the maximum requirement; actual deployment of reserves will vary from hour to hour.

Figure 4-41: Max Capacity Need for ERM by Month for 2025-2029 Need

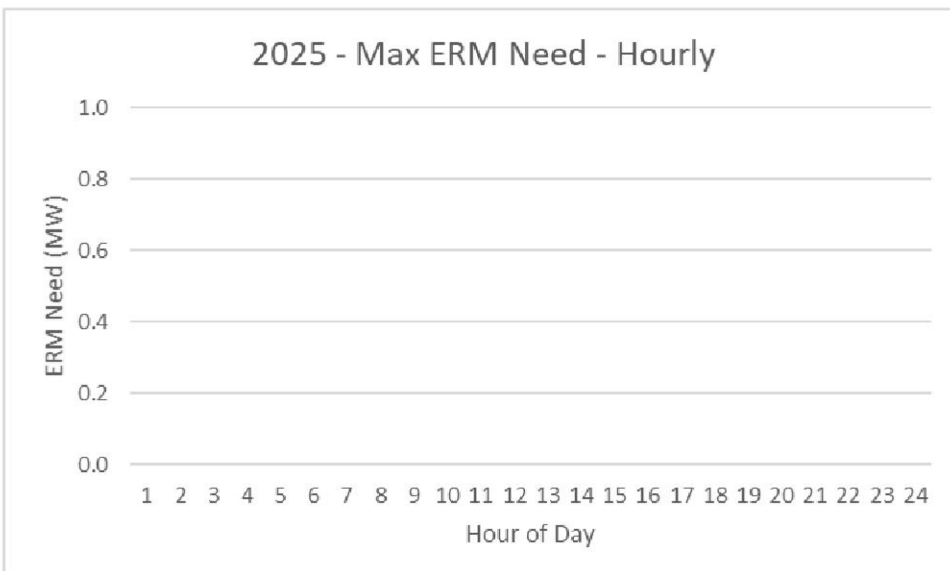


Figure 4-42: Max Capacity Need for ERM by Hour for 2025-2029 Need

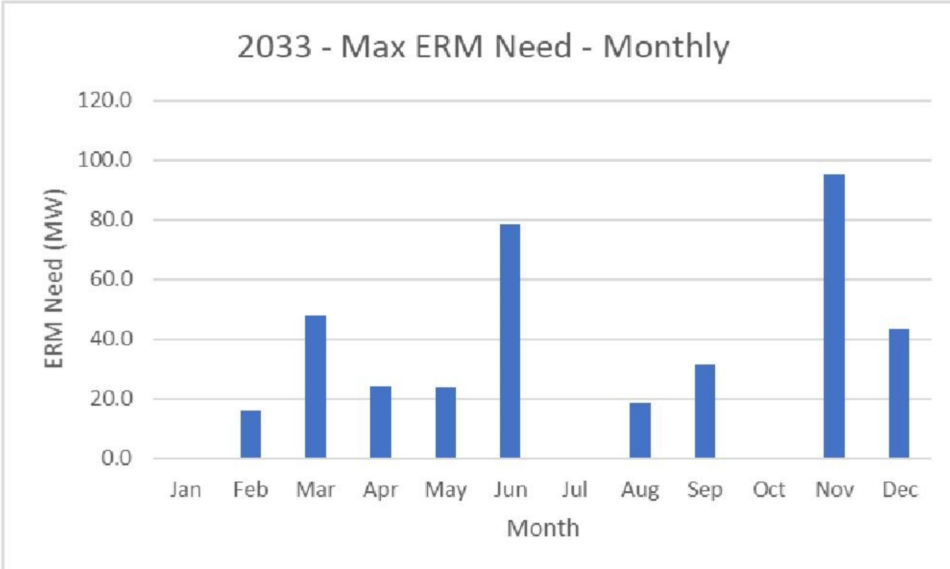


Figure 4-43: Max Capacity Need for ERM by Month for 2030-2034 Need

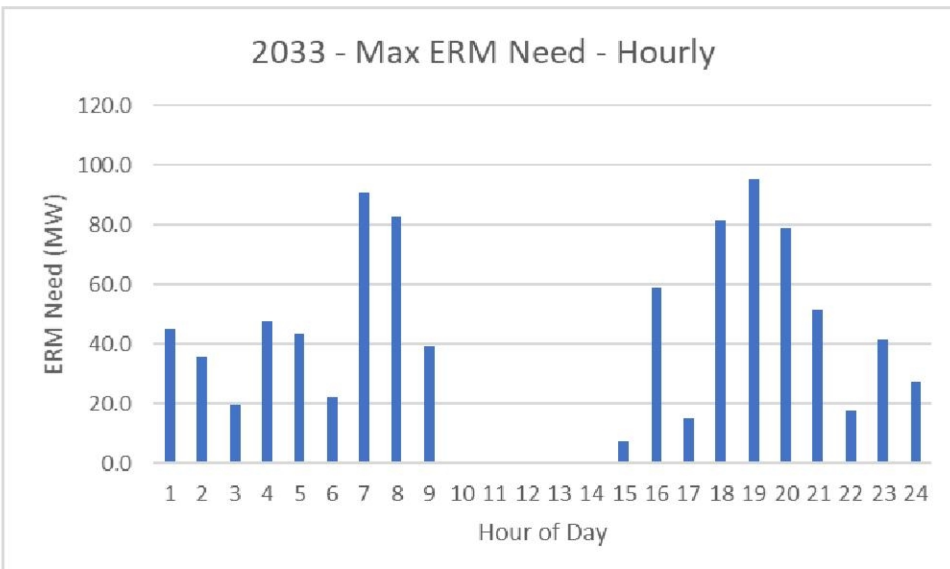


Figure 4-44: Max Capacity Need for ERM by Hour for 2030-2034 Need

5. Reliability Analysis

A separate reliability analysis was performed on the various scenarios using the ERM developed within the IGP process. The Hawaiʻi Island ERM guideline is 30%. For each scenario, a PLEXOS analysis was conducted on the resulting Grid Needs portfolio. Over the planning horizon, each hour was checked for compliance with the 30% ERM guideline. In each scenario, the added resources to the portfolio comply with the 30% ERM guideline, leaving no hours of unserved energy in the study horizon for the Grid Needs Assessment. The following section describes the unfulfilled ERM need under each scenario if no resources were added based on the assumptions of planned resources, PPA contracts and existing fossil generation status, as described in Section 3.6.

5.1. Summary of Reliability Analysis Results

Under all scenarios, there is sufficient capacity through 2030 to serve the forecasted load. The following figures show ERM needs between 2031-2034. The PGV and Hu Honua Scenario does not have any ERM needs through 2034 due to the expansion of PGV and the addition of Hu Honua. These two firm renewable generators provide sufficient capacity even with HEP's PPA expiring in 2031 and Hill 5, Hill 6, and Puna Steam being unavailable for dispatch.

In the Base Scenario, because existing PPA contracts are not extended, if no new resources are added, the 30% ERM cannot be met starting in 2031, and reaches a shortfall up to 95 MW in November 2033.

Figure 5-1: Base Scenario, Seasonal ERM Need

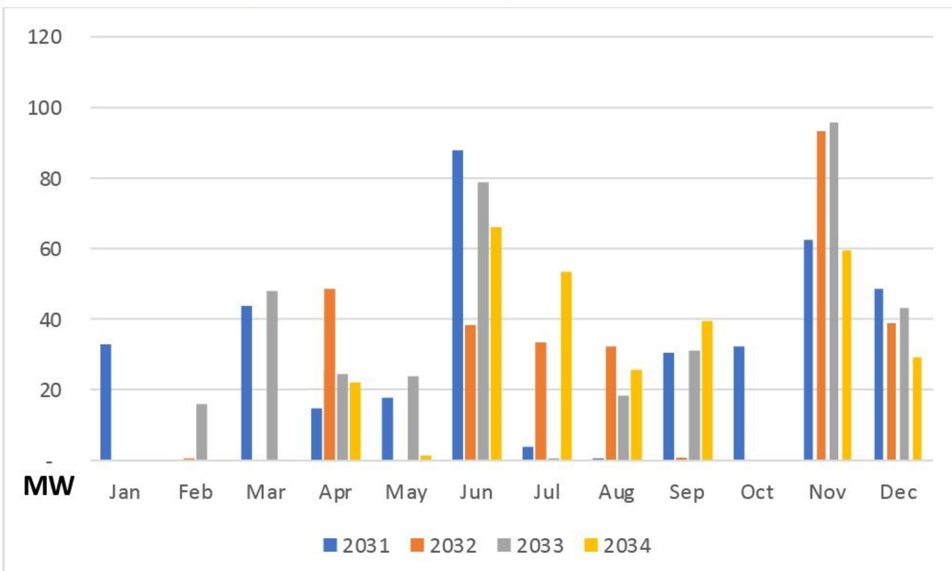
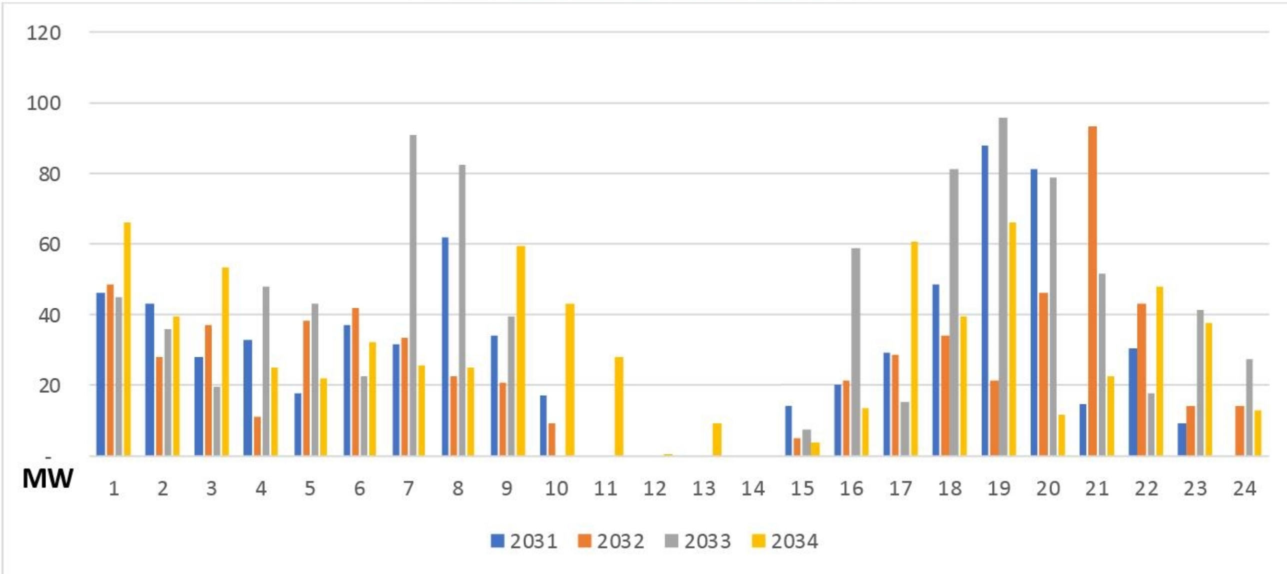


Figure 5-2: Base Scenario, Hourly ERM Need



In the PPA Contract Extensions Scenario, contracts over the next several years that will reach the end of their term are assumed to be extended. Compared to the Base Scenario, the ERM need if no new resources are added is significantly less. The ERM need reaches up to 83 MW in 2033, in part driven from the assumed termination of HEP in 2031.

Figure 5-3: PPA Contract Extensions Scenario, Seasonal ERM Need

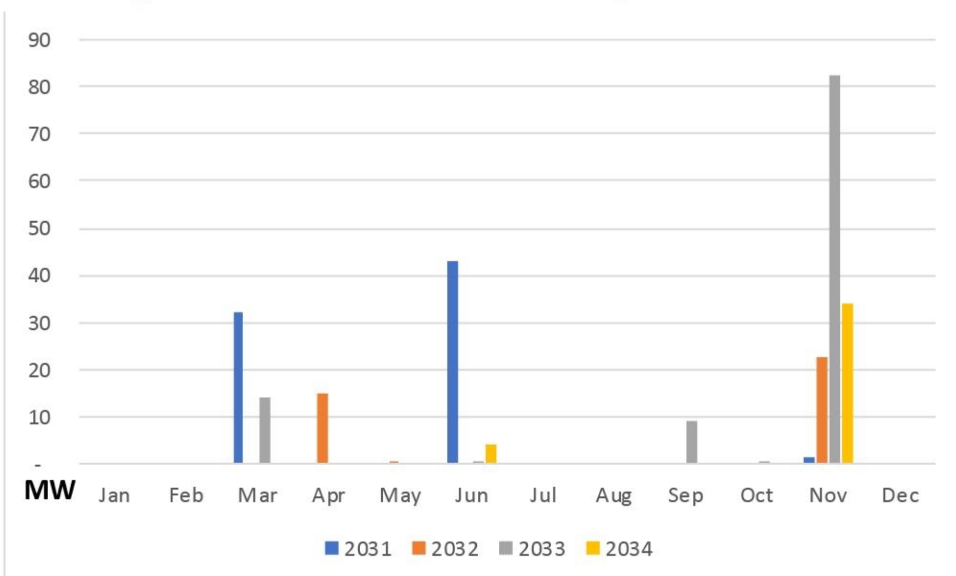
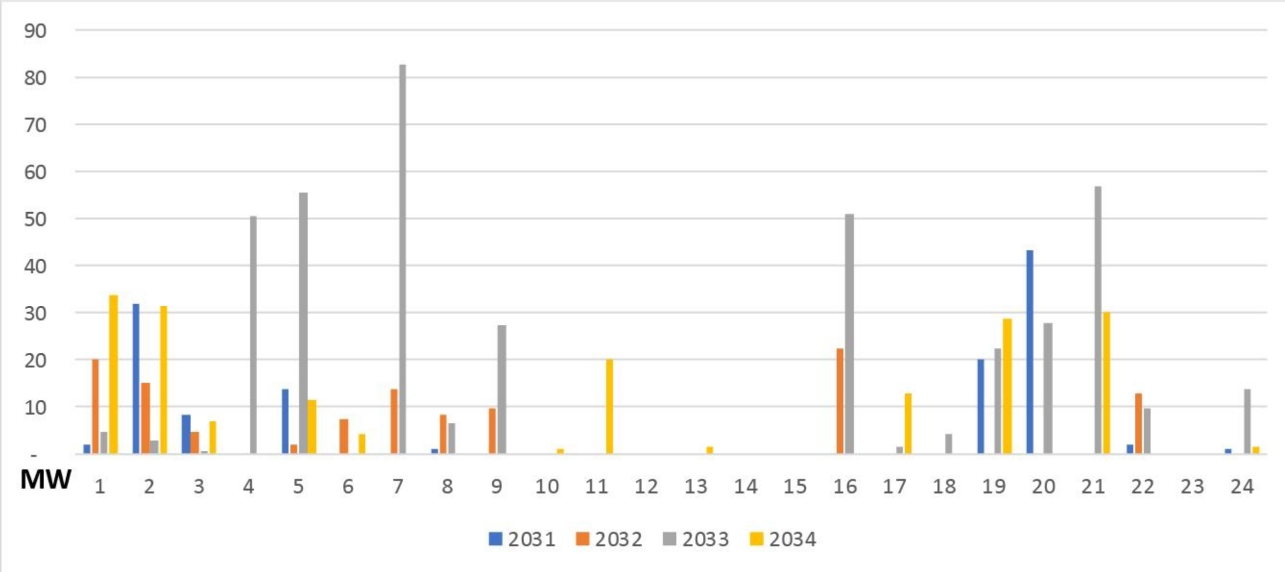


Figure 5-4: PPA Contract Extensions Scenario, Hourly ERM Need



The High Electrification Scenario is similar to the Base Scenario with the electric vehicle layer increased by 30%. As expected, potentially significant shortfalls of meeting the 30% ERM start in 2031 if no new resources are added.

Figure 5-5: High Electrification Scenario, Seasonal ERM Need

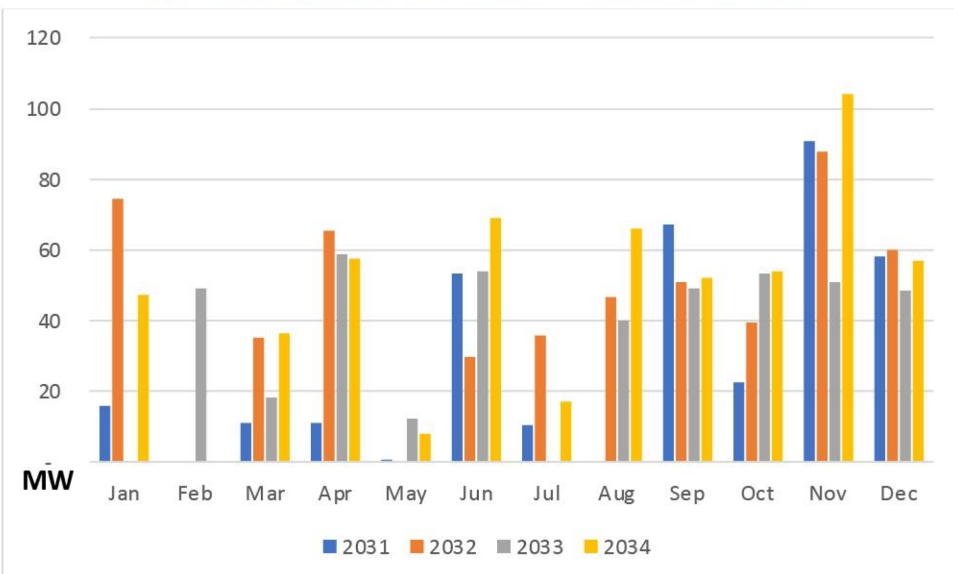
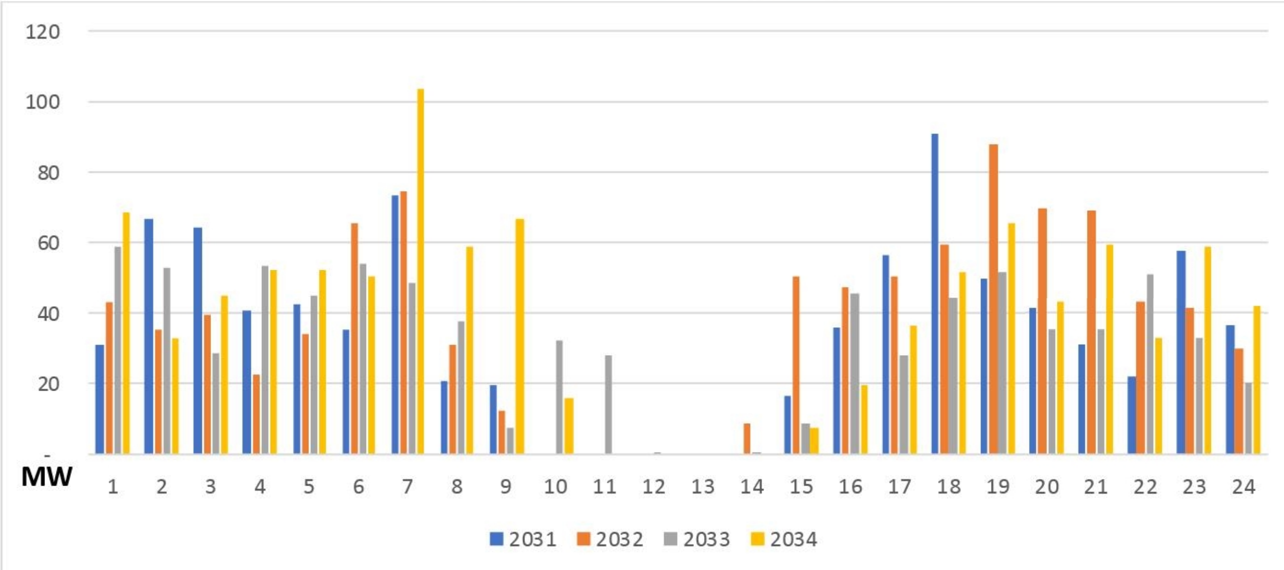


Figure 5-6: High Electrification, Hourly ERM Need



As new resources are added through the solution sourcing process, a reliability analysis may be conducted to ensure the ERM is met over a specified planning horizon.

6. Low Renewable Analysis Results

The PPA Contract Extensions Grid Needs portfolio was stress tested for years 2025-2029 using 10 forced outage loops on thermal generating units and the minimum production profile for PV, wind and hydro resources based on the lowest hourly production observed in past weather years.

6.1. Historical and Past Weather Year Production Profiles

For the low renewable generation sensitivity, historical production was used for existing wind, future wind, and hydro facilities. Estimated historical capacity factors were used for distributed PV. Stage 1 and 2 RFP projects and future PV use production profiles developed by the NREL System Advisor Model[8] using data from the NREL National Solar Radiation Database.[9]

The low renewable profiles for the low renewable case was based on the minimum in each hour across the years of data available. Shown below in Figure 6-1 and Figure 6-2 is a comparison of the average hourly solar and wind profiles across the past years and the minimum profile that was used in this low renewable generation analysis.

[8] See https://sam.nrel.gov/

[9] See https://nsrdb.nrel.gov/

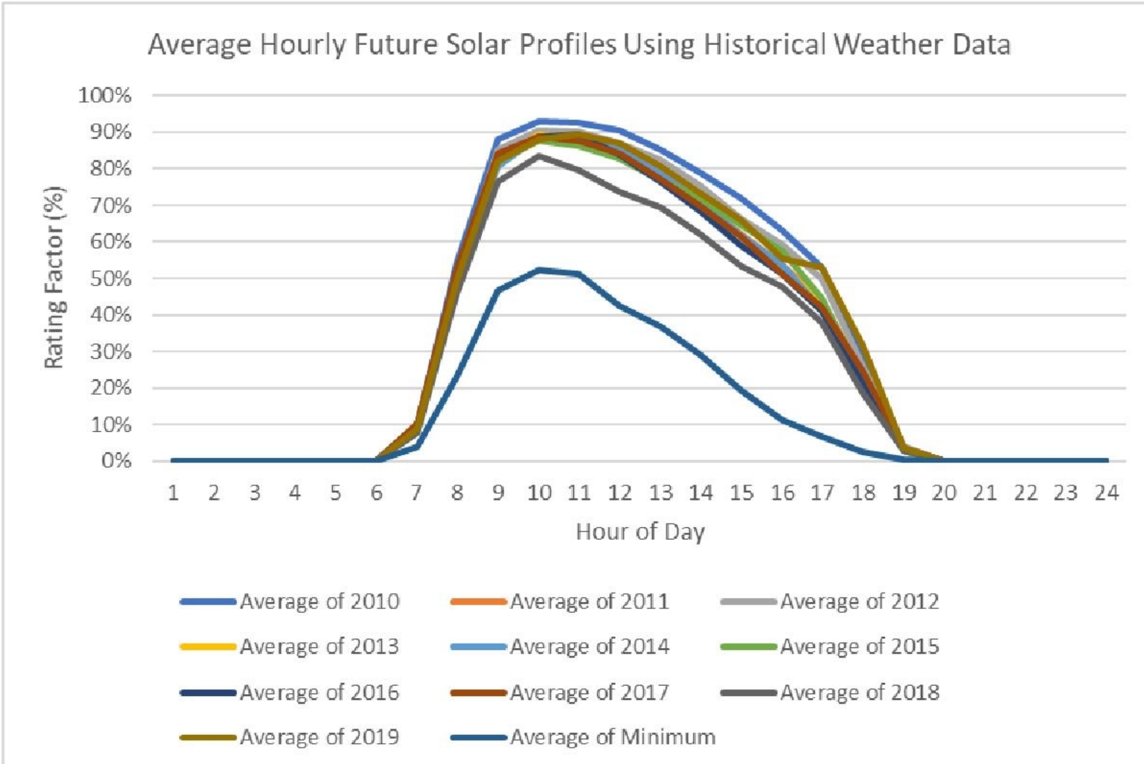


Figure 6-1: Example of Minimum Profile Used for Future PV Resources

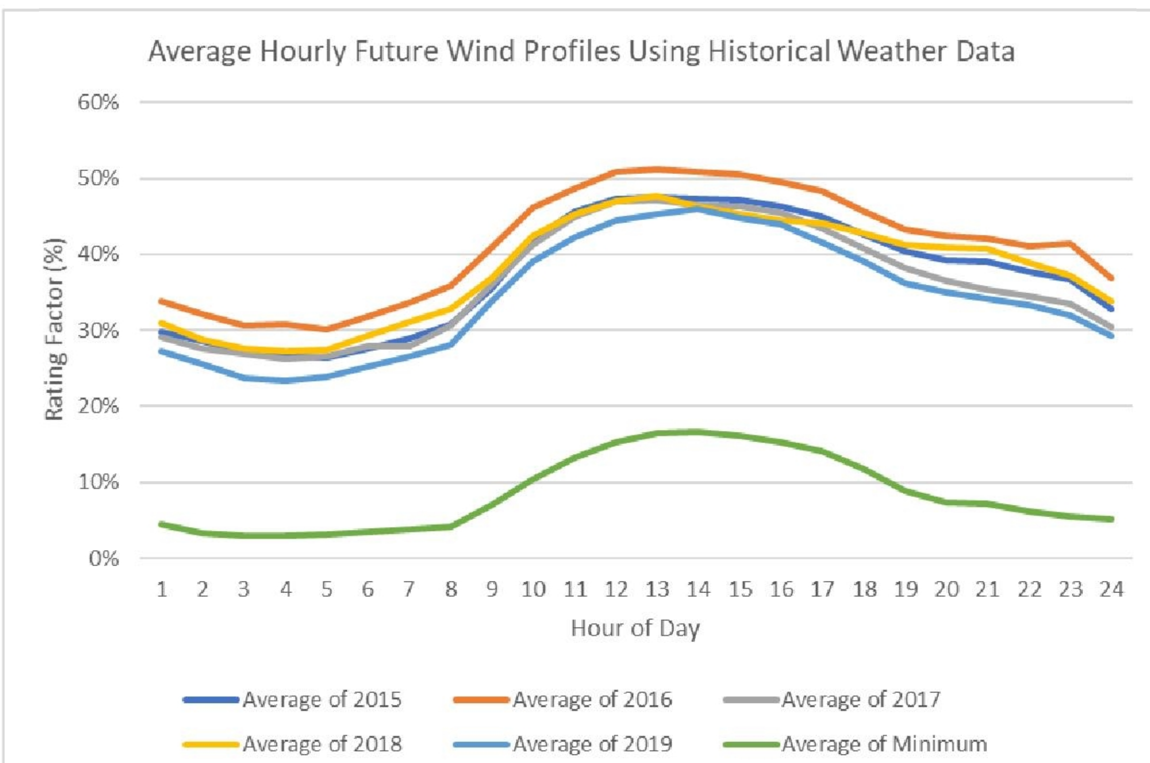


Figure 6-2: Example of Minimum Profile Used for Future Wind Resources

6.2. Results of the Low Renewable Sensitivity

Shown below in Figure 6-3 and Figure 6-4 are the number of hours of unserved energy and the total MWh of unserved energy, respectively, for each of the outage loops.

Figure 6-3: Number of Hours of Unserved Energy in the Low Renewable Analysis

Unserved Energy Hours											
Year	Mean	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7	Sample 8	Sample 9	Sample 10
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0.3	0	0	1	1	0	0	1	0	0	0
2029	0.4	0	1	0	0	1	0	0	1	1	0

Figure 6-4: Amount of Unserved Energy in the Low Renewable Analysis

Unserved Energy (MWh)											
Year	Mean	Sample 1	Sample 2	Sample 3	Sample 4	Sample 5	Sample 6	Sample 7	Sample 8	Sample 9	Sample 10
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0.002	0	0	0.013	0.003	0	0	0.001	0	0	0
2029	0.004	0	0.011	0	0	0.009	0	0	0.008	0.012	0

Based on this analysis, the PPA Contract Extensions Scenario is able to maintain reliability under low solar, wind, and hydro conditions and varying generating unit outage samples. Unserved energy under these conditions was negligible.

7. Transmission Grid Needs Analysis

7.1. Summary of Transmission Needs

The transmission needs analysis is intended to present past study results and high-level analysis results in order to inform near-term solution sourcing, to identify the current understanding of the state of system security on Hawaiʻi Island, to identify areas and conditions of high risk operation, and to identify remaining gaps for resource needs with the need for continued detailed studies. Future study plans are also described at the end of this section.

The following past studies are included as part of this assessment:

- RFP Stage 2 projects system impact study ("SIS") performed in PSS®E
- RFP Stage 2 projects SIS – Island Wide PSCAD study

- Minimum inertia assessment
- Distribution fault stability analysis

The following recommendations are made from the studies listed above:

- Continued requirement of grid-forming ("GFM") control for all future centralized inverter-based resource ("IBR") plants where this is feasible,[10] since the system stability is reduced with higher reliance on only grid-following ("GFL") control.
- Distributed energy resources ("DER") are a major contributor to the total energy needs of the grid. The behavior of existing and new DER during system events is a critical factor in determining Grid Needs. It is important that all DER provides grid-supportive capabilities to the extent feasible.
- Need for inertia to limit the rate of change of frequency ("ROCOF") during system contingency to avoid further potential tripping of DER interconnected on the distribution system.
- Need for voltage support, which can come from (1) centralized IBR plants through control tuning to supply reactive power during faults, and supply more reactive power during nominal under-voltages, or (2) supplemental voltage control devices, such as STATCOMS or synchronous condensers, or DER with extensive testing. Future PPAs should consider specifying additional performance requirements for voltage control, including response characteristics, Q priority, and VAR capability at zero or low active power levels.
- Need for fault current to keep efficacy of the distribution protection system and ensure the system survives distribution faults. The fault current can be provided by synchronous condensers.

From the high-level analysis, the near-term steady-state needs for the Grid Needs portfolio are identified as follows:

1. Voltage support needs in East Hawaiʻi require operation of a minimum number of the existing generating units (i.e., Hill 5 and/or 6 and/or Puna Steam);
2. Voltage support needs in South Hawaiʻi depend on the presence of the Pakini Nui wind farm; and
3. Potential future thermal overloads in the Waikoloa area if additional future generation is connected near the area.

These concerns may be mitigated by:

1. Voltage requirements in East Hawaiʻi can be met without operation of synchronous generating units in the area through addition of dynamic reactive power sources (e.g., synchronous condenser conversions or additions, Static Var Compensator) on the east side of the island or by reconductoring the L6200 transmission line.
2. Voltage needs in South Hawaiʻi would require new dynamic reactive power sources closer to the area of concern or maintaining the renewable generation in the local area in the event the existing resource does not continue operation.

[10] Grid forming capability is presently commercially feasible from standalone storage, paired storage, and statcom devices.

If existing wind farm PPAs do not continue past their current contract dates, replacement of generation at or near the same areas are needed. For continuation of existing renewable contracts, the latest technology and controls capabilities of the technology should be leveraged to the extent feasible. There are many potential benefits to extending existing contracts. Permitting has been completed, the land is already zoned for the activity, existing interconnection structure is already in place, and in many instances the community has accepted the project. These should significantly lower prices of existing facilities for their new term. To the extent new technologies and controls can be leveraged in these existing facilities at the end of their new term, further benefits can be derived from the system.

Future detailed studies will also need to be performed to evaluate other resource needs such as dynamic voltage support and FFR, which are expected to be covered in upcoming system stability studies.

It is important to note that the resource needs identified in this document are based on the studies performed to date and do not preclude other resource needs that have not been identified or studied at this time.

At current and increasing renewable penetration levels after Stage 1 and 2 projects are in service, there may be other needs for system security that are not yet fully understood or identified within the industry. It is impossible to have 100% certainty on future impacts to power system reliability caused by drastic generation resource changes while simultaneously determining the optimal solution/mitigation for future grid issues.

From this study, to enhance system resilience, future resources should be procured in strategic locations to maintain past levels of resource locational diversity. Hawaiʻi Island is unique in its transmission system and Grid Needs, which require balanced generation supplied from different areas of the island to avoid planning criteria violations such as voltage violations or potential cross-island transmission line overloads. As indicated in the high-level analysis and past analyses, generation heavily provided by one area of the island can result in low voltage violations on the opposite side of the island or cross-island transmission tie-line overloads. The recent Stage 1 and 2 procurements selected 120 MW of solar and energy storage systems in West Hawaiʻi. Therefore, new resources located in East and South Hawaiʻi would be highly beneficial for the near-term system Grid Needs under the proposed Grid Needs portfolios.

Regardless of locational preference, the location of available renewable resources on the island and the interests of landowners, community and developers need to be taken into consideration. Resource potential[11] for wind and photovoltaic for Hawaiʻi Island was recently evaluated by NREL as part of the IGP process. Though the final assumptions for IGP have not been finalized at this time, the indicative potential for each renewable resource both show it is feasible to site either renewable resource in East or South Hawaiʻi.

The Company evaluated existing transmission substations available for interconnection with the intention of streamlining and lowering interconnection costs. The preliminary results of

[11] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/stakeholder_council/20200818_sc_heco_tech_potential_final_report.pdf

the transmission capacity analysis indicate there is ample capacity at existing substations located in East Hawaiʻi for future Stage 3 resources. The final capacity values must be confirmed during detailed evaluations in the RFP process as well as during the respective system impact studies.

7.2. System Security Assessment

A high-level system security assessment was performed based on the Stage 2 RFP SIS. Conclusions and recommendations from other studies and analyses performed internally, prior to and in parallel with the SIS, are also considered and referenced in this assessment. The assumptions and conclusions of each study will be considered to qualitatively indicate the near-term resource needs for system security.

It is expressly noted that these studies and analyses have a limited scope specifically tailored for the project(s) and desired study problem/condition. A high-level assessment composed of several smaller studies is not sufficient or indicative of all system Grid Needs and should be better informed by a full-scale system security study that considers multitudes of potential operating conditions and considers the entire range of system contingencies covered by the Transmission Planning criteria.

An in-depth system security study to include dynamic stability analysis, is currently planned for the IGP process and will be performed as soon as possible with current procured generating resources.

7.2.1. Stage 2 SIS in PSS®E

Hawaiian Electric commissioned Siemens PTI to perform the Stage 2 Renewable and Grid Services RFP SIS for the two Hawaiʻi projects: Puakō Solar PV + Battery Storage (“Puakō Solar”) and Keahole Battery Energy Storage (“Contingency Storage”). The study was mainly performed in PSS®E with Puakō Solar modeled as GFM control (they refer to their specific mode as Grid Supporting Inverters, “GSI”) and Keahole Battery Energy Storage was modeled as GFL control. Puakō Solar generation owner determined that their GFL mode would not operate correctly due to the low levels of system strength at their proposed point of interconnection (“POI”). To operate at the POI, Puakō Solar needs to run their plant in GFM control mode.

The generation dispatches assumed for the SIS were informed by the Stage 2 production simulations. Several operating conditions were extracted from the hourly production simulation data (e.g., Evening Peak, Daytime Minimum, maximum instantaneous DER, maximum instantaneous wind, etc.) and were narrowed down to 4 total dispatch scenarios to determine the most severe dispatches to study for the system. The dispatches were reduced to minimize costs and schedule impacts. The initial dispatches served as the pre-project dispatches, representing system conditions prior to the addition of the two projects. They were then adjusted to include the two projects, known as the post-project dispatches, with various generation levels to stress system conditions.

For dispatches with low amounts of synchronous generation online, a key assumption used in this study is the requirement of a minimum amount of rotating inertia on the system. For Hawaiʻi Island, the recommended minimum inertia was approximately 350 MW-s and was determined by preliminary analyses performed prior to Stage 2 RFP evaluations. This analysis will be explained and discussed in further detail in its dedicated section below.

Steady-state results showed no thermal violations after the two projects were added to the system. There was a slight high voltage violation near Waimea that was determined to be a pre-existing condition and not caused by the project additions.

Dynamic stability results were found to be stable in both pre- and post-project simulations for the list of studied contingencies, which included a select few line faults and generation trip contingencies. The full list of transmission line contingencies is typically not studied in the SIS in order to reduce the study cost and duration. A few contingencies that were studied did result in 1-2 blocks of under-frequency load shedding ("UFLS"). The first two blocks of load shed represent roughly 15% of the system load. The load shedding identified here was found to be acceptable according to the Transmission Planning Criteria: loss of largest generator and faults with delayed remote clearing allow up to 15% of UFLS.

A key assumption for the dynamic stability simulations is related to the DER blocking or often referred to as "momentary cessation."[12] The DER blocking assumption used in this study was optimistic, such that all DER enters momentary cessation at 0.1 pu, there is no time delay in recovery after voltage is restored, and the rate of recovery back to nominal output is within 6 cycles. In other words, all DER output is expected to return immediately after the system voltage is restored above the threshold. There is general uncertainty within the industry regarding how DER will behave under these contingency conditions. An accurate representation of aggregate DER requires highly detailed surveying and analysis of the existing DER on the system. A more conservative assumption would be higher voltage threshold levels and extended recovery times.

In summary, the dispatches that were studied with the resource and DER assumptions indicated the system is stable after addition of the Stage 2 projects. The rest of the SIS results can be referenced in the official report by Siemens PTI.[13]

7.2.2. Stage 2 Island-Wide PSCAD Study

Hawaiian Electric commissioned Electranix to perform the *Hawaiian Electric Island-Wide PSCAD Studies (Stage 2 IRS)*[14] in parallel with the Siemens PTI study for the two Hawai'i Island projects. This study was performed in PSCAD/EMTDC with unprecedented level of detail and was

[12] NERC Reliability Guideline BPS-Connected Inverter-Based Resource Performance, "Momentary Cessation, also referred to as "blocking," is when no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. This occurs because the power electronic firing commands are blocked, and the inverter does not produce active or reactive current (and therefore no active or reactive power)." https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

[13] The System Impact Study for the Puakō Solar project will be included in the IRS Amendment for the project which will be filed in Docket No. 2020-0189.

[14] Available at, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210630_electranix_report.pdf

focused on system stability. Both GFL and GFM versions of the Stage 2 project models were evaluated to identify potential risks if GFM technology was not employed with the extreme dispatches that were considered and to identify potential benefits or risks of requiring GFM operation. For Puakō Solar, the project was studied only as GFM for reasons mentioned in the previous section.

A large portion of time and effort was committed to establishing the island-wide database in PSCAD and checking Stage 2 PSCAD models for basic model adequacy in order to commence with the study. A full island-wide model for each transmission system did not exist prior to this study and Electranix was tasked with the entire model creation. The full model consists of the existing transmission system, existing synchronous units, existing renewable plants and future Stage 1 and Stage 2 renewables plants.

Due to the high accuracy of PSCAD/EMTDC simulations, the computational burden and the simulation processing times are extensive, even with the state-of-the-art workstation and parallel computing, and supplemental software must be used to avoid compiling/linking issues when using multiple different vendor-supplied models.

The generation dispatches that were selected for this study were based on the dispatches created for the Stage 2 SIS by Siemens PTI with some minor modifications. The dispatch with the worst simulation results in PSS®E was used as the base and then all synchronous condensers were removed from the dispatch for Hawaiʻi island. The resulting dispatch for the PSCAD study had only the PGV plant and small hydro units as the remaining synchronous machines on the system.

The DER blocking assumption used in this study assumed that all DER enters momentary cessation at 0.9 pu. However, like the PSS®E analysis, there is no time delay in recovery after voltage is restored. In some fault scenarios, DER may fail to recover completely if the voltage is not restored above 0.9 pu. This results in a large generation loss that must be supplemented by the remaining generation on the system.

Results with only Puakō Solar operating as GFM and Contingency Storage as GFL showed the N-0 condition, or pre-contingency flat run, is stable but UFLS and instability were observed for 6 of 16 contingencies that were studied. If Contingency Storage operates as GFM, there is a slight improvement in results and 4 of 16 contingencies had UFLS and instability. With tuning of both Stage 2 projects, 3 of 16 contingencies resulted in instability and load shedding, two of which are loss of critical larger generators.

Since Puakō Solar can only be modeled in GFM mode, there was no GFL case for Hawaiʻi Island. However, GFL results for other islands (i.e., Oʻahu and Maui) showed that the N-0 (normal everyday) condition is not stable, or the slightest perturbation causes instability. The study concludes that GFM should continue to be required and implemented into the system due to the inadequacy of GFL control technology to ensure stability in a system relying heavily upon IBR. The comparison with Oʻahu and Maui studies also illustrated the benefits to system stability provided from the operation of the synchronous geothermal facility (i.e., PGV).

The loss of PGV or Puakō Solar were deemed to be significant events that resulted in excessive levels of UFLS despite Stage 2 plant control tuning. Other instabilities in the form of system-wide oscillations are persistent in multiple results. Sustained oscillations in both frequency and voltage were observed as synchronous machines oscillate against inverter-based resources.

Specific issues related to GFM control are still unknown but are suspected to manifest when plants are near their equipment limitations. One case in this study is when Puakō Solar appeared to prioritize current-limiting control over GFM control, worsening the undervoltage condition seen during the contingency and delaying voltage recovery.

In summary, the dispatches that were studied with the resource and DER assumptions indicated that the post-Stage 2 project system may remain operable for the modeled base cases, with excessive UFLS for some events. However, the analysis has identified some outstanding issues and instabilities which warrant additional analysis. The full results can be referenced in the official report by Electranix.

7.2.3. Stage 2 Studies Key Assumptions & Results Comparison

The following Figure 7-1 shows the differences in key assumptions used for each Stage 2 study.

Figure 7-1: Stage 2 Studies – Differences in Key Assumptions

Assumption	Stage 2 SIS by Siemens PTI	Stage 2 Island-Wide PSCAD Study by Electranix
Simulation Tool	PSS®E (positive sequence)	PSCAD (EMTDC)
Stage 1 Projects Control Technology	Grid-following	Grid-following
Stage 2 Projects Control Technology	Puakō Solar – Grid-forming Contingency Storage – Grid-following	Puakō Solar – Grid-forming Contingency Storage – Grid-following & Grid-forming
Synchronous Condensers	Puna CT3, Keahole CT4 and Keahole CT5 available as synchronous condensers	None
DER Blocking / Momentary Cessation	Voltage threshold = 0.1 pu No time delay in recovery	Voltage threshold = 0.9 pu No time delay in recovery

PSS®E is a positive sequence simulation software which has limitations to simulate weak strength system dynamics during small time scale; PSCAD/EMTDC is an electromagnetic transient (EMT) simulation software which can fully represent system dynamics regardless of system strength in short time frame transient/dynamic simulation. Also, IBR inverter models have more accurate representation in the PSCAD/EMTDC than in the PSS®E. The simulation tools for each study were different but use of both tools are becoming increasingly necessary as the amount of renewable generation percentage increases on the system. Traditional positive sequence software (e.g., PSS®E and PSLF) simulation results start to become unreliable, which raises concerns regarding control stability, due to numerical instability in IBR models as the system grid strength weakens due to the displacement of synchronous machines and the inability to model fast controller dynamics. This dilemma necessitates the need for improved positive sequence models (which are not available and can take a very long time to develop properly) and use of a highly accurate and detailed simulation tool such as PSCAD (which is prone to very slow simulation times due to the amount of detail modeled). The results in PSCAD are highly accurate but it is currently not feasible to run full system studies solely using this software due to the limitations of modern computing hardware available to the Company.

Stage 1 projects were all modeled as GFL, while Stage 2 projects were modeled as GFM for Puakō Solar, GFL for Contingency Storage in PSS®E, and both GFL and GFM for Contingency Storage in PSCAD. The two studies are generally the same in this aspect and running the Keahole BESS as GFM showed some benefit to the system.

For the study performed in PSS®E, synchronous condensers were added, which assist in system grid strength and indirectly reduce the likelihood of numerical instability seen during simulation. As a sensitivity, no synchronous condensers were added for the study performed in PSCAD.

The DER blocking (also called "momentary cessation") assumed for each study used opposite ends of the spectrum. The settings for DER blocking are highly ambiguous since they can vary between inverter manufacturers and even between specific inverter models from a single manufacturer. Therefore, it is extremely difficult to know with absolute certainty how to model DER and what the true parameters are for DER blocking to be used in the system models. Future research to refine these parameters specific for each island system is being planned.

It is worth noting that DER with FFR functionality was not included in the Stage 2 SIS model but will be included in future study.

In general, the results from the Stage 2 SIS by Siemens were stable or had minimal oscillation when projects are operated in GFL mode (with the exception of Puakō Solar), synchronous condensers are added to the system, and with optimistic assumptions regarding DER blocking. On the contrary, the Stage 2 Island-wide PSCAD study by Electranix indicated that even with all Stage 2 projects in GFM mode, with no synchronous condensers online, and DER blocking assumptions, the system can experience excessive UFLS and instabilities for multiple contingency scenarios. The DER assumptions regarding ride-through and blocking affect UFLS; and the UFLS impacts could be reduced if DER ride-through without blocking is improved over the model assumptions. However, DER assumption adjustments are not able to mitigate instabilities such as oscillations and equipment limitations with GFM equipment. It is unknown what alternatives to synchronous sources and GFM may improve oscillations without additional study. It is theorized that it may be possible to mitigate with continued tuning or installing supplemental equipment such as Power System Stabilizer or Power Oscillation Damper at suitable locations, however the underlying cause and mode of oscillation needs to be well understood and may require extensive analysis. In any case, follow-up analysis considering synchronous condensers and alternatives, sensitivity to DER blocking parameters and other mitigations is required.

7.2.4. Minimum Inertia Assessment

During the Stage 2 RFP evaluation stage, a system analysis was performed aimed at identifying the minimum inertia needs of each island system. The minimum inertia assessment was based on meeting two objectives in the system response to the loss of the single largest generating unit and accompanying trip of rooftop legacy PV systems: (1) limiting the negative ROCOF to no more than 3 Hz/s, and (2) provide at least a half-second buffer before unacceptable load shedding occurs. A 0.1 Hz margin is applied to the frequency setting of the unacceptable load shed block.

The maximum ROCOF of 3 Hz/s is based on the current knowledge of DER ROCOF ride-through requirements according to IEEE 1547-2018 sub-clause 6.5.2.5 "Rate of change of frequency (ROCOF) ride-through" for Category III and the Company's latest SRD V2.0. At ROCOFs greater than 3 Hz/s, it may be possible for large amounts of DER to trip off, which would result in a generation loss that can be larger than the current single largest generating unit on the system and potentially lead to system collapse.

The minimum inertia is based on the following form of the swing equation (ignoring damping):

$$\frac{2H}{f_n} \cdot \frac{df}{dt} = P_a$$

where H is the system inertia constant given in MJ or MW, $\frac{df}{dt}$ is the ROCOF in Hz/s, f_n is the nominal frequency in Hz, and P_a is the accelerating power (i.e., the difference between mechanical and electrical power) in MW. Given that the accelerating power is the largest single unit plus rooftop legacy PV capacity, a minimum inertia is calculated based on a ROCOF of 3 Hz/s.

Using the same equation, a minimum inertia is also estimated given the half-second timeframe to unacceptable load shedding. The time constraint accounts for the time periods before and after legacy PV trips. The impact of acceptable load shedding is not accounted for in this process. For the first time period before legacy PV trips, the accelerating power is solely due to the loss of the largest unit. The time to legacy PV tripping is estimated given the frequency deviation corresponding to 59.3 Hz, which is the point where legacy PV trips. The second time period after legacy PV trips is based on the accelerating power equal to the sum of the largest unit and legacy PV. An inertia value is calculated such that the sum of the two time periods is greater than one half-second.

The minimum inertia is then the higher of the two inertias calculated from the ROCOF constraint and the time constraint.

For Hawai'i Island, the analysis recommends a minimum inertia of approximately 350 MW-s to be applied for all dispatch conditions. The minimum inertia recommendation here was applied to Stage 2 production simulations and also for the Stage 2 SIS dispatches for the Siemens

PSS®E study. Dispatches for other studies mentioned in this section do not assume minimum inertia but consider synchronous condensers as mitigations. It is possible that GFM control may influence the required inertia due to the inherent inertia-like response, but the exact impact has yet to be determined. Future refinement of this analysis is needed when accurate GFM models are obtained.

It is worth noting that this ROCOF assumption exceeds the operational experience of the system and it is expected that unforeseen issues may come to light during operational experience. To date, the increase in ROCOF has resulted in required changes to the UFLS protection speed, modifications to existing plant control systems, and presented challenges obtaining accurate frequency measurements for rate of change of frequency calculations in the protection equipment.

7.2.5. Hawaiʻi Island Distribution Fault Stability Analysis

Another analysis performed in parallel with the Stage 2 SIS studies is a stability study focusing on prolonged distribution fault clearing times due to reduced fault currents on the distribution system, which is ultimately caused by reduction of traditional sources of fault current (i.e., synchronous machines). According to protection studies, the longest expected distribution faults will be a three-phase ("3PH") fault for 2 seconds (120 cycles) and a single-line-to-ground ("SLG") 40 ohm end-of-line fault for 20 seconds (1,200 cycles). Traditionally, distribution faults were never an issue for the bulk transmission system, but with the displacement of synchronous machine-based generation by inverter-based generation, these clearing times prompted a study to ensure system stability for distribution faults which are more common than transmission faults.

Distribution faults were analyzed in this study as an extension of the Hawaiʻi Island Distribution Protection Study. Faults consisted of a 3PH bolted fault for 2 seconds and SLG 40-ohm faults for 20 seconds. System upgrades, considering only synchronous condensers, were also evaluated in this study since they can provide significant amounts, more than 5 times, of fault current compared to IBR. The study assumed the addition of Stage 1 RFP resources only since the Stage 2 SIS was ongoing at the time of the analysis.

The analysis indicated that certain distribution faults cause system instability and UFLS events. The cases that had instability were run with three synchronous condenser options: (A) Puna CT3, (B) Keahole CT4 & CT5, and (C) Puna CT3, Keahole CT4 & CT5. When any synchronous condenser option was added, all instability was mitigated for most cases; however, frequency instability remained for 3PH faults of a single case.

End-of-line faults were run for the single case with and without synchronous condenser options. Without synchronous condensers, instability was observed for the select distribution faults studied. After including any synchronous condenser option, all instability was mitigated except for a single dispatch variation. For this single dispatch, frequency instability was observed and critical clearing times ("CCTs") were identified for these three faults with the lowest CCT being 117 cycles. It is suspected that this particular instability was caused by a modeling issue with one of the Stage 1 projects and should be investigated for future studies after the Stage 1 restudies have been finalized.

To avoid system instability caused by 3PH or SLG distribution circuit level faults, the study recommends implementing any of the three synchronous condenser options that were studied.

7.2.6. Summary of Grid Needs for System Security

At current and increasing renewable penetration levels after Stage 2 projects, there will be other needs for system security that are not yet fully understood or identified within the industry. Current analyses are limited in their capabilities due to poor model representation of new resources, constant restudy efforts with updated equipment and the need for more specialized detailed software such as PSCAD that requires new expertise and is very slow to run.

Based on the studies performed to date, it is clear there is a need for additional capabilities and technologies as more IBR are procured even though there is much uncertainty in the future. One of the confirmed needs is the continued requirement of GFM control for all future centralized IBR plants, as recommended by the Electranix Island-Wide study report. The Electranix study results were clear in showing not only the benefits of GFM operation but also that operation with only GFL would result in system instability. GFM inherently provides a degree of stability in their controls during weak grid or high IBR penetration scenarios since they do not rely on fast synchronization with the grid.

Other capabilities needed are inertia and fault current, which can be provided by a resource such as synchronous condensers or other rotating units (e.g., thermal generation). The ROCOF during loss of generation must be limited to a maximum value in order to avoid further potential tripping of DER. GFM may be able to help to a certain extent, but the amount of benefit has not been studied and GFM operation alone also comes with new instabilities that need to be mitigated before full implementation. For fault current, minimum levels of fault current are needed on the distribution network and local upgrades to protection equipment are required for safe and reliable operation. Synchronous condensers can provide higher levels of fault current compared to IBR resources, which may help defer local upgrades to protection equipment. Other alternatives for synchronous condensers will be considered in future studies.

Additional resource needs to cover steady state concerns such as local voltage support will be explored in the high-level analysis portion of this document.

Again, this assessment focuses on studies that have been performed to date and does not preclude other needs that were not identified here. Future detailed studies will also need to be performed to evaluate other resource needs such as voltage support and FFR, which is expected to be covered in the upcoming system stability studies.

7.3. Stage 3 High-Level Steady-State Analysis

In addition to the high-level system security assessment, a high-level analysis is performed here to identify near-term steady state Grid Needs such as voltage support. This analysis is performed solely in PSS®E and does not consider transient stability or inverter control interactions. The analysis here is used to inform additional resource needs based on the fossil generation unit status assumptions discussed in Section 3.5.

Base Scenario (Scenario 1) production simulations and their associated portfolio of Grid Needs were analyzed to develop the dispatches and sensitivities used for this analysis. As discussed later in this section, sensitivities were also analyzed which align with other scenarios that were evaluated, as discussed in Section 3.6.

7.3.1. Assumptions

For this preliminary assessment, analysis was performed on a representative Year 2024.

Year 2024 Representative Base Scenario

Generating units are assumed in-service or not available for dispatch according to the Base Scenario Grid Needs. The key generation assumptions up to Year 2024 are summarized as follows:

- Generation Additions:
  - PGV in-service at old PPA contract levels
  - Stage 1 Hale Kuawehi
  - Stage 1 Waikoloa
  - Stage 2 Puakō Solar
- Modeled Generation Removals:
  - Hawi wind farm
  - Wailuku hydro

Modeled additions and removals past Year 2024 are also summarized as follows:

- Modeled Additions:
  - ~67.8 MW, 265.3 GWh renewable resource (2025)
- Modeled Removals:
  - Puna Steam (2025) (Not Dispatched)
  - Hill 5 (2027) (Not Dispatched)
  - Hill 6 (2027) (Not Dispatched)
  - Pakini Nui wind farm (2028)

Distributed Energy Resources (DER)

CBRE resources are modeled similarly to DG-PV and are aggregated together into a generic category as DER. These DER resources are modeled as aggregate generators on the low-voltage side of distribution load buses.

Fast Frequency Response (FFR)

Since the high-level analysis scope does not include transient stability, FFR resources such as DER FFR and Contingency Storage were not modeled.

7.3.2. Methodology

Base Dispatches

From the Base Scenario production simulation, hours were filtered according to specific parameters and the following dispatch hours in Year 2024 were selected for analysis:

- Evening Peak
- Evening Minimum
- Maximum DER
- Maximum Wind Generation (also the hour with maximum total system demand)
- Maximum Net Stage 1 & Stage 2 Generation (also the hour with minimum thermal generation online)
- Minimum East Generation

Load and generation values were taken directly from the production simulation to create the dispatches with some minor adjustments to represent generation in realistic operating conditions (e.g., units with values below their required minimum power output levels were assumed offline). Sensitivities for these base dispatches are explained in the following section.

Sensitivity Dispatches

From the base dispatches, sensitivity dispatches were created considering different potential operating conditions that align with the Scenario Analysis discussed in Section 3.6. Included in the list of sensitivities is a Minimum East Generation case, which is intended to determine the Transmission Grid Needs when minimum generation is available on the East side of the island to illuminate transmission needs to enhance the resilience of the Hawaiʻi Island system. The sensitivity dispatches are described below:

- **Evening Peak**
  - **V1:**
    - **Base dispatch:** Evening Peak (PGV, Hill 5, Hill 6, Keahole DTCC, Puna Steam, Pakini Nui Wind, Stage 1, Stage 2)
    - **Adjustments:**
      - Turning off Keahole DTCC and instead turn on HEP DTCC
      - Maximize Stage 2 Puakō Solar output by first reducing thermal synchronous units to minimums and then Stage 1 output
  - **V2:**
    - **Base dispatch:** Evening Peak V1 (PGV, Hill 5, Hill 6, Puna Steam, HEP DTCC, Pakini Nui Wind, Stage 1, Stage 2)
    - **Adjustments:**
      - Remove Hill 5, Hill 6, and Puna Steam units
      - Increase Stage 1 Hale Kuawehi output
  - **V3:**

        - **Base dispatch:** Evening Peak V2 (PGV, HEP DTCC, Pakini Nui Wind, Stage 1, Stage 2)
        - **Adjustments:**
            - Turn on Hawi Wind (assuming not removed and retained)
            - Shift wind generation from Pakini Nui Wind to Hawi Wind
- **Maximum Wind Generation**
    - **V1:**
        - **Base dispatch:** Maximum Wind Generation (PGV, Hill 5, Hill 6, Pakini Nui Wind, Stage 1, Stage 2)
        - **Adjustments:**
            - Turn off Pakini Nui Wind (assuming no wind generation)
            - Increase Stage 1 Hale Kuawehi output
- **Minimum East Generation**
    - **V1:**
        - **Base dispatch:** Minimum East Generation (Keahole DTCC, Puna Steam, Pakini Nui Wind, Stage 1, Stage 2)
        - **Adjustments:**
            - Remove Puna Steam (last unit on the East)
            - Turn on HEP STCC
    - **V2:**
        - **Base dispatch:** Minimum East Generation V1 (Keahole DTCC, HEP STCC, Pakini Nui Wind, Stage 1, Stage 2)
        - **Adjustments:**
            - Keahole as STCC
            - HEP as DTCC
    - **V3:**
        - **Base dispatch:** Minimum East Generation V2 (Keahole STCC, HEP DTCC, Pakini Nui Wind, Stage 1, Stage 2)
        - **Adjustments:**
            - Turn off Pakini Nui Wind (assume no wind generation)
            - Increase Stage 1 Hale Kuawehi output

Analysis and Criteria

Steady state analysis is performed for cases representing the base and sensitivity dispatches described earlier. Automatic AC contingency analysis using PSS®E was performed considering contingencies of:

- Loss of a single line or transformer on the transmission system
- Loss of a few select N-2 elements on the transmission system

Line flows and voltages on the 69 kV transmission system and radial 34.5 kV system were monitored in this analysis.

The following planning criteria was applied for the analysis:

1. Thermal Overloads: Monitored elements with line flows greater than their normal rating (Rate A) in the base cases or greater than their emergency rating (Rate B) under contingencies are flagged as overloads.
2. Voltage Thresholds: Under normal or contingency conditions, voltages greater than 1.05 pu or below 0.90 pu at the respective base voltage are flagged as voltage violations.

7.3.3. Thermal Capacity Analysis Results

For all studied dispatch scenarios and sensitivities, no thermal overloads were observed. The worst thermal loading for each case is summarized in Figure 7-2 and the case with the highest thermal loading is highlighted in red text, which is the Evening Peak V3 sensitivity case at 90% of Rate B on L7200 for a contingency of L8200 transmission line. It is noted that most of the generation in this case is near the Waikoloa area and additional generation for future RFPs should discourage interconnecting to this area to avoid the thermal overload conditions that require significant transmission line additions or upgrades. In addition to addressing heavy thermal loading, avoiding the area could increase resource geographic diversity which is beneficial to resilience.

Figure 7-2: Max Thermal Loading Results

Case	Worst Contingency	Maximum Loading (% RateB MVA)	Maximum Loading Branch
HEL2024_STG3_EveMin	L8700+L8500 PUNA-POHO & KAUM-KEAM	49.8	6500
HEL2024_STG3_EvePeak	L9600 KAMAOA	57.2	6600
HEL2024_STG3_EvePeak_v1	L8200 MAUNA LANI	62.9	7200
HEL2024_STG3_EvePeak_v2	L8200 MAUNA LANI	76.7	7200
HEL2024_STG3_EvePeak_v3	L8200 MAUNA LANI	89.7	7200
HEL2024_STG3_MaxDER	L8700+L8500 PUNA-POHO & KAUM-KEAM	47.8	6500
HEL2024_STG3_MaxNetStg1+Stg2	L7100 ANAEHOOMALU-POOPOOMINO	55.5	8100
HEL2024_STG3_MaxWind	L9600 KAMAOA	68.4	6600
HEL2024_STG3_MaxWind_NoWind	L6300+L8700 PUNA-KILA & PUNA-POHO	45.9	6500
HEL2024_STG3_MinEastGen	L8300 MAUNA LANI-OULI	60.7	8100
HEL2024_STG3_MinEastGen_v1	L8300 MAUNA LANI-OULI	58.2	8100
HEL2024_STG3_MinEastGen_v2	L8800 HONOKAA-HAINA	54.4	6200
HEL2024_STG3_MinEastGen_v3	L8800 HONOKAA-HAINA	60.3	6200

7.3.4. Voltage Analysis Results

For all studied dispatch scenarios and sensitivities, there were several cases with minimum voltage violations or close to violation. The minimum voltages seen in each case is summarized in Figure 7-3. Planning criteria violations are highlighted in red and cases close to the criteria limit are highlighted in yellow.

Figure 7-3: Minimum Voltage Results

Case	Worst Contingency	Minimum Voltage (pu)	Minimum Bus Name
HEL2024_STG3_EveMin	L8600 KAHALUU	0.968	KEAUHOU
HEL2024_STG3_EvePeak	L6300 PUNA	0.951	PANAEWA
HEL2024_STG3_EvePeak_v1	L8600 KAHALUU	0.955	KEAUHOU
HEL2024_STG3_EvePeak_v2	L8600 KAHALUU	0.954	KEAUHOU
HEL2024_STG3_EvePeak_v3	L8600 KAHALUU	0.909	KEAUHOU
HEL2024_STG3_MaxDER	L8600 KAHALUU	0.956	KEAUHOU
HEL2024_STG3_MaxNetStg1+Stg2	L8600 KAHALUU	0.906	KEAUHOU
HEL2024_STG3_MaxWind	L6300 PUNA	0.955	PANAEWA
HEL2024_STG3_MaxWind_NoWind	L8600 KAHALUU	0.916	KEAUHOU
HEL2024_STG3_MinEastGen	L7700 WAIMEA	0.907	KAMUELA
HEL2024_STG3_MinEastGen_v1	L8800 HONOKAA-HAINA	0.889	WAIPUNA
HEL2024_STG3_MinEastGen_v2	L8800 HONOKAA-HAINA	0.888	WAIPUNA
HEL2024_STG3_MinEastGen_v3	L8800 HONOKAA-HAINA	0.872	WAIPUNA

All base dispatch scenarios did not show any minimum voltage violations. However, two cases, maximum net Stage 1 & Stage 2 and minimum east generation base dispatches, are very close to criteria violation. Several sensitivity cases, mainly sensitivities regarding minimum amounts of east generation, show clear violations of the planning criteria and must be mitigated. Also, one evening peak sensitivity shows it is near a violation of the criteria.

From these results, the near-term voltage needs can be categorized as follows:

1. Immediate voltage support needs in East Hawaiʻi caused when existing generating units, Hill 5 and 6, and Puna Steam are not available for dispatch
2. Potential voltage support needs in South Hawaiʻi caused by the absence of nearby generation (i.e., Pakini Nui wind farm)

With the modeled unavailability of the steam generating units, there will be an immediate need for voltage support for future operating conditions that have little to no units operating on the east. If Hill 5, Hill 6, and Puna Steam are not available, the remaining available generation units on the east will be PGV, Puna CT3 and small diesels at Kanoelehua Substation. Future operating conditions modeled PGV in continuous operation except for outages, while Puna CT3 and diesels are uneconomic to run when compared to low cost renewable projects. However, as PGV will not always be available and must undergo planned and unplanned outages. The sensitivities built around the minimum east generation base dispatch represent this potential operating condition and indicate there will be drastic criteria violations along the entire east side of the island (i.e., low voltage criteria violation is not found in only 1 or 2 buses, but the entire east side of the island). Mitigations for this issue will be considered in the next section of the analysis.

The second concern for voltage support needs is in South Hawaiʻi and is caused by periods when there is no wind generation in the area (i.e., no Pakini Nui output). Though there was no voltage violation identified with the dispatches studied, this was a high-level analysis and did not consider an exhaustive list of sensitivities (e.g., increase of local load, etc.). Historically, this has been a known issue and is generally mitigated by having wind generation available in the area. However, if wind farm contracts in this area are not extended, this issue should be closely monitored in future studies and may require mitigation depending on the future location of generating resources and the operating state of the system.

7.3.5. Mitigation Results

Mitigations were considered for the voltage violations identified in the previous section. The mitigation option for voltage violations consisted of adding sources of reactive power to the system. Probable locations for synchronous condensers, which assumes conversions of existing generation units, were the only locations considered to site the reactive power sources. Other technologies, such as centralized IBR, may also serve as reactive power sources. The exact size and locations of the mitigation must be reevaluated as part of any new resource's SIS and future studies. Figure 7-4 below shows voltage violation results with an 18 MVAR reactive power source added to Puna substation and a 32 MVAR reactive power source added to Keahole substation.

Figure 7-4: Minimum Voltage Results with Reactive Power Source Mitigation

Case	Worst Contingency	Minimum Voltage (pu)	Minimum Voltage Bus
HEL2024_STG3_MaxNetStg1+Stg2_18MVAR-Puna	L8600 KAHALUU	0.906	KEAUHOU
HEL2024_STG3_MinEastGen_18MVAR-Puna	L8600 KAHALUU	0.968	KEAUHOU
HEL2024_STG3_MinEastGen_v1_18MVAR-Puna	L8800 HONOKAA-HAINA	0.937	WAIPUNA
HEL2024_STG3_MinEastGen_v2_18MVAR-Puna	L8800 HONOKAA-HAINA	0.936	WAIPUNA
HEL2024_STG3_MinEastGen_v3_18MVAR-Puna	L8600 KAHALUU	0.931	KEAUHOU
HEL2024_STG3_MaxNetStg1+Stg2_18MVAR-Puna_36MVAR-Keahole	L8600 KAHALUU	0.906	KEAUHOU

With an 18 MVAR reactive power source added at Puna substation, the low voltage violations are mitigated and are well within planning criteria for the East Hawaiʻi voltage concerns. However, the results show that, for South Hawaiʻi, both an 18 MVAR reactive power source at Puna and a 32 MVAR reactive power source at Keahole are not sufficient to mitigate the local voltage concerns. A mitigation solution closer to the area of concern is needed and should be considered in future analyses.

Another mitigation option considered the reconductoring of L6200, which was a mitigation identified in past analyses for voltage violation issues on West Hawaiʻi. The issue identified in the past analyses was related to the lack of generation on the west side of the island combined with the distribution of load on the system, which caused the potential of voltage collapse in West Hawaiʻi. It is possible East Hawaiʻi may face the same or similar issues to some extent. The voltage violation results with L6200 reconductored are shown in Figure 7-5.

Figure 7-5: Minimum Voltage Results with L6200 Reconductor Mitigation

Case	Worst Contingency	Minimum Voltage (pu)	Minimum Bus Name
HEL2024_STG3_MinEastGen_recon6200	L7700 WAIMEA	0.959	KAMUELA
HEL2024_STG3_MinEastGen_v1_recon6200	L8800 HONOKAA-HAINA	0.932	WAIPUNA
HEL2024_STG3_MinEastGen_v2_recon6200	L8800 HONOKAA-HAINA	0.933	WAIPUNA
HEL2024_STG3_MinEastGen_v3_recon6200	L8600 KAHALUU	0.933	KEAUHOU

The results show that the L6200 reconductoring also mitigates the low voltage violations in East Hawaiʻi and is a viable option to consider. For clarification, no new reactive power sources were added to the system in these results.

7.3.6. Summary of Grid Needs for Steady State Analysis

From the analysis results, the near-term steady-state concerns are identified as follows:

1. Voltage support needs in East Hawaiʻi require operation of a minimum number of the existing generating units (i.e., Hill 5 and/or 6 and/or Puna Steam);
2. Voltage support needs in South Hawaiʻi depend on the presence of the Pakini Nui wind farm; and
3. Potential future thermal overloads in the Waikoloa area if additional future generation is connected near the area.

Immediate voltage concerns in East Hawaiʻi can be mitigated with the addition of reactive power sources on the east side of the island, such as new or generating units converted to synchronous generators or by reconductoring the L6200 transmission line. These voltage concerns should be mitigated prior to any decisions to retire generating units on the east side of the island. Alternatively, remaining existing synchronous generation in the area (e.g., Puna CT3) may be committed and dispatched to also provide this resource but is not a desirable solution for achieving high levels of RPS goals.

Voltage needs in South Hawaiʻi can be mitigated by adding reactive power sources closer to the area of concern or utilize existing mitigation consisting of renewable generation in the local area. Planned removal of the local wind farm should consider replacement of generation (e.g., wind, PV, etc.) at or near the same area in South Hawaiʻi to continue to mitigate the low voltage concerns. Generation replacement in the form of wind should not consider continued use or refurbishment of older wind turbine technology and should upgrade to the latest wind turbine generator technology and controls (e.g., GFM) if feasible.

Future generation in the Waikoloa area, after the addition of Stage 1 and Stage 2 projects, have the potential to cause thermal overloads in the area which may require significant transmission additions or upgrades in the area. The transmission system of Hawaiʻi Island is unique to other island systems and should have generation sources balanced on each side of the island for optimal power flows. Past analyses and this high-level analysis clearly indicate the potential voltage collapse concerns when the majority of generation is produced solely on one side of the island. Other reliability concerns such as resiliency will be touched upon in the next section.

The identified near-term steady-state needs are only partial in determining the full needs of the system. In addition to the needs identified in the system security assessment and this high-level steady-state analysis, system security study needs will need to be assessed after any future projects are selected. Synchronous condensers may be able to address multiple needs for steady-state and stability issues and should be considered as an enabling mitigation/technology to allow for future high penetration levels of renewable generation.

7.4. Interconnection Options

The interconnection options analysis will identify existing substation sites for interconnection to help obviate the need for developers to construct new substations for interconnection. The analysis also helps to visualize the resulting locational and geographic diversity of generation resources in the Base Scenario caused by the proposed planned removals. The need for diversity and potential exclusion areas from issues learned in the high-level analysis section is also introduced. Evaluating the locational diversity of existing units and, to the extent possible, balancing supply and demand in different parts of the island is a part of the need for a larger, detailed system resiliency analysis that should be performed in the future.

7.4.1. Evaluation of Existing Resources and Confirmed Procurements

Using the Base Scenario Grid Needs as the input assumptions for this analysis, the locations of all generating resources are visualized by general location on Hawai'i Island in the figures below. The total generation capacity of all available resources (both existing and confirmed procurements, i.e., Stage 1 & 2 projects) for Hawai'i Island in Years 2024 and 2029 are shown in Figure 7-6 for the Base Scenario. The generation here contains both renewable and fossil-fuel powered resources assumed in the Base Scenario model.

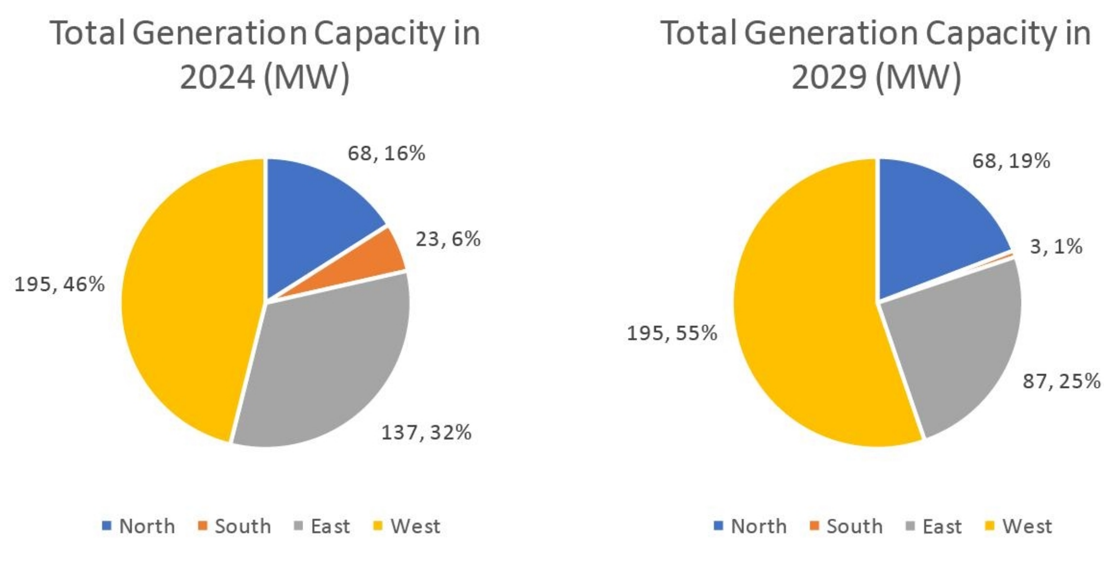


Figure 7-6: Total Generation Capacity in Years 2024 & 2029 for the base scenario

When considering only renewable generation, the proportion of available capacity in each location of Hawaiʻi Island shifts drastically in the near term due to modeled removals of existing wind, hydro and synchronous machines and assumed new resource locations. The total renewable generation capacity for Hawaiʻi Island in Years 2024 and 2029 in the Base Scenario are shown in Figure 7-7.

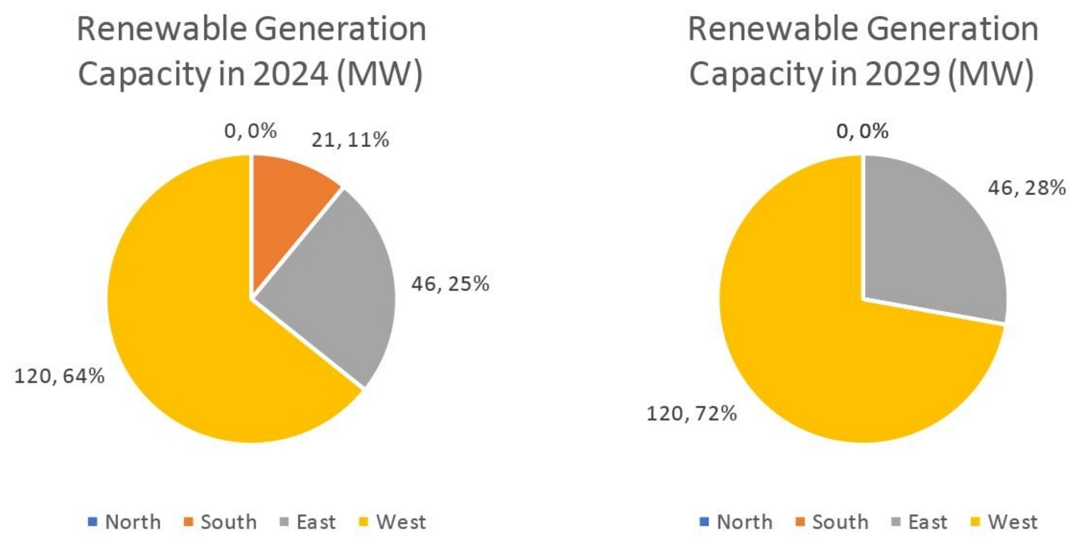
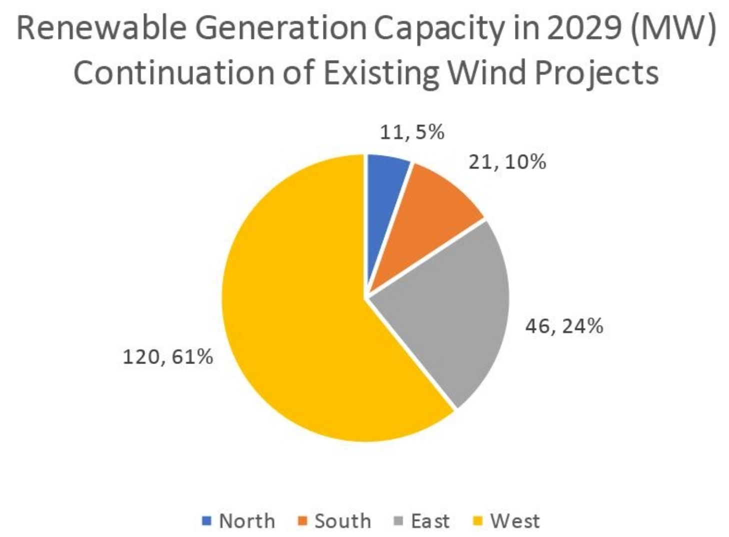


Figure 7-7: Renewable Generation Capacity in Years 2024 & 2029 in the Base Model

In the Base Scenario model resource assumptions, without considering the location of future resource procurements, there is no renewable generation in North or South Hawaiʻi, due to the assumed removal of the existing wind facilities, and almost all the renewable generation in East Hawaiʻi is provided by PGV. The other renewable generation in East Hawaiʻi are very small existing hydro units, and the larger hydro is assumed to be removed. The total renewable energy modeled as removed is approximately 42 MW of high-capacity-factor resources. The Stage 1 and 2 project procurements would need to provide 72% of total renewable generation and are modeled as located in West Hawaiʻi.

New future resources would need to be procured in strategic locations to maintain existing levels of resource locational diversity. The Hawaiʻi Island transmission system requires balanced generation supplied from different areas of the island to avoid planning criteria violations, such as voltage violations or potential cross-island line overloads, and to provide reliability and resilience for a variety of natural events. As previously indicated in the high-level analysis section, generation heavily provided by one area of the island can result in low voltage violations on the opposite side of the island or cross-island tie overloads. Therefore, if the assumed existing resources are displaced, they would need to be replaced by new resources similarly located in East and South Hawaiʻi for system Grid Needs under the modeled Stage 3 resource plans.

Therefore, existing wind projects should be given consideration to continue past their current contract because of their benefits to the system by alleviating Grid Needs and providing additional locational diversity with already-built interconnection facilities. Renegotiation of current wind projects will consider maximizing plant capabilities to provide grid services through enhancement of wind turbine generator ("WTG") and controls upgrades. For comparison, the total renewable generation capacity for Year 2029 assuming the continuation of existing wind projects is shown in Figure 7-8.



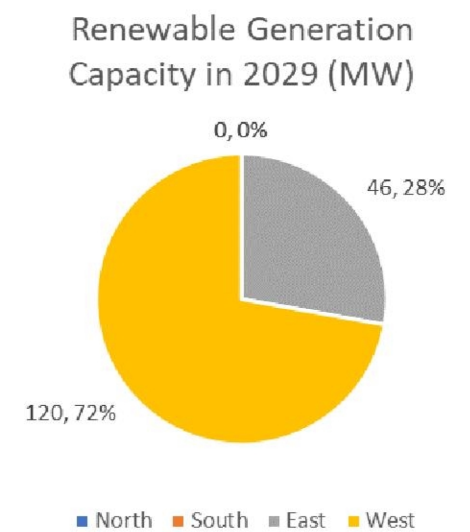


Figure 7-8: Renewable Generation Capacity in 2029, Continuation of Existing Wind Projects Compared to Modeled Removal (Bottom)

System resiliency should also be evaluated in future detailed analyses and include scenarios considering if the island would be able to sustain system demand in the event of natural events, as it has provided to date through hurricanes, earthquakes, floods, tsunami and volcanic activity. For example, scenarios to explore are events that may cause the critical cross-island ties to be taken out, which will force the system to heavily rely on local generating resources. From the available generation capacity in the current modeled Grid Needs portfolio it is possible East Hawaiʻi may need to rely on existing fossil-fuel synchronous generation if demand is high enough or when PGV is out of service under these extreme, but possible, system conditions.

7.4.2. Potential Existing Substation Sites

To help obviate the need for developers to construct new substations for interconnection, the Company identified a list of existing substations ranked by difficulty of future expansion to accommodate new resources. Substations identified as "feasible" are all in breaker and half configuration and generally indicate there is an unused bay that is available for use or require 1 new breaker to accommodate the interconnection. Substations identified as "less feasible" generally indicate there is physical space for expansion but significant issues exist such as reconfiguration of 69 kV lines, land issues, etc. The "feasible" and "less feasible" substations are as follows:

- Feasible
  - Ouli (however, this is located in the transmission-constrained Waikoloa area)
  - Kanoelehua
  - Palani (after planned upgrades)
- Less Feasible
  - Puueo
  - Poopoomino
  - Pohoiki (however, this substation has a large connected capacity and only two existing transmission lines)
  - Pepeekeo

Of the "feasible" and "less feasible" substations identified, select substations were chosen for further analysis to identify preliminary values for available transmission capacity. Substations in both East and West Hawaiʻi were considered to provide options for future developers regardless of the locational preferences previously identified. In East Hawaiʻi, Kanoelehua, Puueo and Pohoiki were selected. In West Hawaiʻi, Palani and Poopoomino were selected. Even though Ouli was categorized as "feasible," it was not considered because it (1) is in close vicinity with the Mauna Lani substation, which is the POI for a 60 MW Stage 2 project in the Waikoloa area, and (2) is located in the constrained Waikoloa transmission system.

Another substation that was considered is the Keamuku substation, which was not identified in the categories above. This substation was considered since there had been past interest at this POI, but the substation would require a significant rebuild. A rebuild of this critical substation which connects multiple transmission lines at a single substation would be highly beneficial to the system by providing increased reliability. If schedule and costs allow for the expansion, this may be a reasonable option with some reliability and resilience benefits.

Regardless of locational preference, the location of available renewable resources on the island and the interests of landowners and developers must be taken into consideration. Resource potential for wind and photovoltaic for Hawaiʻi Island was recently evaluated by NREL as part of the IGP process. Though the final assumptions for IGP have not been finalized at this time, the figures that will be provided here are indicative of the location of available high potential wind and solar resources. The wind potential is provided in Figure 7-9 and the photovoltaic potential is provided in Figure 7-10. Both figures illustrate the potential to site either renewable resource on both East or South Hawaiʻi. Therefore, if transmission and interconnection for new facilities can be accommodated, the locational options for new renewable sites could be expanded, and the investment in new transmission and interconnection facilities could facilitate increased locational diversity and additional capacity from under-utilized potential locations.

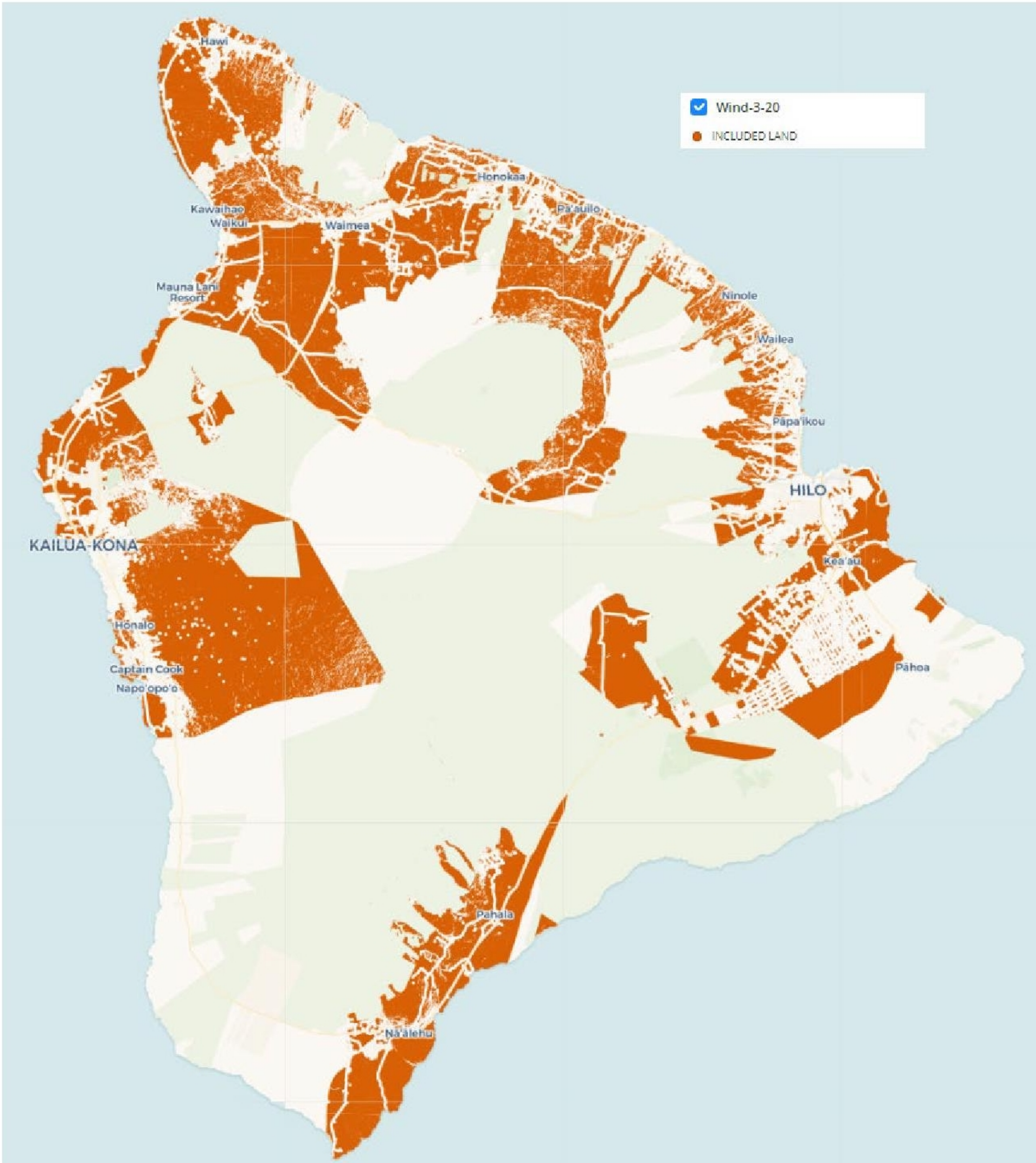


Figure 7-9: Hawaiʻi Island Wind Resource Potential (Wind-3-20)

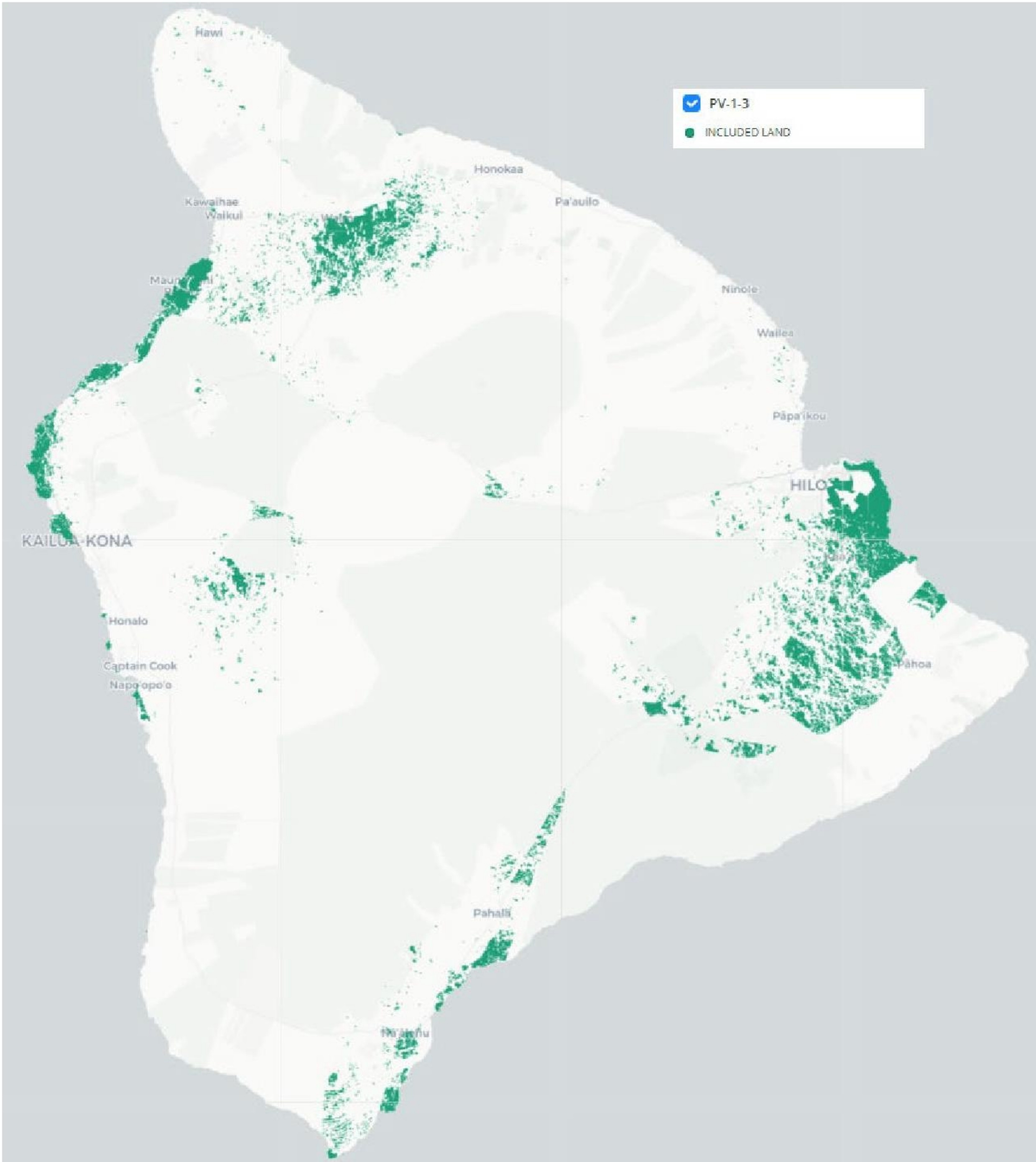


Figure 7-10: Hawai'i Island Photovoltaic Resource Potential (PV-1-3)

7.4.3. Transmission Capacity Analysis

Similar to previous Land RFI analyses that were made available to developers prior to the Stage 1 and Stage 2 RFPs, the approximate available capacity at each chosen substation site will be provided, assuming the addition of generation at the single POI. The analysis here does not consider multiple projects connecting to more than one interconnection point. Consideration for multiple projects will need to be evaluated during the competitive procurement process when there is greater clarity of the exact proposal sizes and locations.

Assumptions

This capacity analysis assumed the following:

- Stage 1 & 2 projects are available
- PGV at 46 MW capacity
- No planned unit removals
- Additional generation from FFR is not considered
- Cross-island transmission tie overloads are not considered and are assumed to be mitigated
- Voltage violations are not considered

Preliminary Results

The preliminary results of this transmission capacity analysis for the chosen 69 kV transmission substations are shown in Figure 7-11. The capacities shown here are based on thermal overloads only and indicate there is ample capacity on both East and West Hawaiʻi for future resources. The values below are based on existing and planned generation additions up to the Stage 2 projects and are subject to change based on the available generation fleet (e.g., generation removals, retirements, additions) and other system changes (e.g., load or transmission line additions, etc.). Lastly, the values shown below must be confirmed during detailed evaluations in the procurement process as well as during the SIS.

Figure 7-11: Transmission Capacity Analysis Results

General Location	Substation	Interconnection Limit (MW)
East	Kanoelehua	61 (note 3)
East	Pohoiki (PGV)	26 - 34 (note 3, 5, 6)
East	Puueo	97 (note 3, 5)
West	Palani	93 (note 4, 5)
West	Poopoomino	57 (note 4, 5)
West	Keamuku	50 (note 4)

Notes:

1. For each substation, it is assumed there is no additonal generation at other locations during the interconnection limit analysis.
2. New individual generators shall follow the largest single point of failure limit for Hawaii Island (30MW).
3. East interconnection limits are interdependent.
4. West interconnection limits are interdependent.
5. Under certain N-1 outages, total substation export must be reduced to 30MW to maintain the single point of failure requirement.
6. Interconnection limit may change based on approved capacity of PGV geothermal plant.

7.5. Future Studies

This transmission Grid Needs Assessment for Hawai'i Island focused on energy procurement needs and steady-state constraints. System stability performance and control interactions, for all resources including new IBR projects will be evaluated in future, more detailed studies. To fully identify the Grid Needs, the Company has initiated a near-term system stability study (2028 scenario) in both PSS®E and PSCAD/EMTDC based on more detailed modeling and simulations, and is planning to kick off the next IGP cycle for a longer term timeframe analysis from the end of this year or the beginning of next year. Additional Grid Needs, such as dynamic voltage support, frequency response, inertia needs, and short circuit current support, will be investigated in detail in the system stability study.

The following topics will be addressed by the next IGP cycle studies:

- DER blocking (momentary-cessation) requirements
- System fault current needs assessment
- System reactive power support assessment
- System inertia needs assessment
- System frequency response needs assessment
- UFLS effectiveness review

8. Recommended Grid Needs for Solution Sourcing and RFP Requirements

The recommended Grid Needs for the various services, except for ERM, are based on the PPA Contract Extensions Scenario and are summarized in Figure 8-1 below. The PPA Contract Extensions Scenario results case was selected as a 'least regrets' pathway because these Grid Needs are needed regardless of whether or not the PPAs for the existing independent power producers are extended. The capacity for ERM is based on the 2030 Base Scenario to ensure reliability, in the event that that existing PPAs are unable to be successfully renegotiated.

The grid services identified below define the required capability of the portfolio. Each grid service may be called upon, up to the hourly megawatt limits. However, the maximum need for each grid service may not be coincident. The temporal charts in Section 4.3 for each grid service further illustrate the time of day and month where the service will be required.

Figure 8-1: Summary of Recommended Grid Needs

Service	Amount
Energy	Up to 58 MW hourly, 206 GWh annually
Load Build	Up to 17 MW hourly, 148 calls annual, 1.1 hours duration
Load Reduce	Up to 58 MW hourly, 55 calls annual, 2.1 hours duration
Upward Regulating Reserve (20-min)	Up to 47 MW hourly
Upward Regulating Reserve (1-min) / Upward Ramp Reserve	Up to 29 MW hourly
Downward Regulating Reserve (20-min)	Up to 22 MW hourly
Downward Regulating Reserve (1-min) / Downward Ramp Reserve	Up to 17 MW hourly
Capacity for Energy Reserve Margin	Up to 95 MW hourly (2030 Need, Base Scenario)

The Grid Needs that were identified in 2025 are not required to be in-service by 2025. Based on the reliability analysis in all scenarios, even if new resources are not acquired, the system should have sufficient capacity through 2030 based on the planned resources expected to reach commercial operations over the next few years. Further, in Scenarios 2 and 3, the incremental 2030 needs are minimal compared to 2025. In other words, once 2025 needs are fulfilled, there are no significant needs for additional resources until after 2030. The Company recommends any future procurement use a commercial operations date no later than the 2028-2030 timeframe to allow for a robust all-source procurement as directed by the Commission. Requiring commercial operations prior to 2028 will limit the types of technologies that may participate in the solution sourcing process and may also lead to higher costs for eligible technologies given the short timeframe. A later commercial operations date will expand the types of technologies and solutions available to the Company. This concept is consistent with the long-term RFP being discussed in the IGP proceeding, and provides an opportunity to diversify the resource portfolio on Hawaiʻi Island.

The Company will also continue to pursue further system stability studies as described in the Report. Near-term synchronous condenser conversions of generating units may be needed to supply voltage support, inertia, and fault current. The Company will continue to determine its need (e.g., based on bids or solutions that are selected in the solution sourcing process) and present such projects to the Commission, if necessary, at the appropriate time.

Additionally, the following RFP requirements are recommended:

- Updated GFM performance requirements for inverter-based resources in the Model PPA
- Require resource additions to be located and interconnected on the east side of the island
- Make available Company substations on the east side of the island to streamline the interconnection process for prospective bidders
- Commercial operations date no later than the 2028-2030 timeframe